ENVIRONMENTAL ASSESSMENT BOARD

Ontario

ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARINGS

VOLUME: 20

DATE: Tuesday, May 28, 1991

BEFORE:

HON. MR. JUSTICE E. SAUNDERS Chairman
DR. G. CONNELL Member
MS. G. PATTERSON Member

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ENVIRONMENTAL ASSESSMENT BOARD
ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARING

IN THE MATTER OF the Environmental Assessment Act, R.S.O. 1980, c. 140, as amended, and Regulations thereunder;

AND IN THE MATTER OF an undertaking by Ontario Hydro consisting of a program in respect of activities associated with meeting future electricity requirements in Ontario.

Held on the 5th Floor, 2200 Yonge Street, Toronto, Ontario, on Tuesday, the 28th day of May, 1991, commencing at 10:00 a.m.

VOLUME 20

B E F O R E :

THE HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

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F. MACKESY	ON HER OWN BEHALF

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L I S T o f E X H I B I T S

---Upon commencing 10:03 a.m.

THE REGISTRAR: Please come to order. This hearing is now in session. Please be seated.

MRS. FORMUSA: Mr. Chairman, yesterday two exhibits, Exhibits 152 and 153, were shown by Mr. Taborek and we have had copies made overnight. Eight copies have been given to Mr. Lucas and additional copies are available at the front.

There is one other matter with respect to corrections to the transcript that I wanted to seek your advice. We have been looking at the transcripts and there are some typographical errors that have been appearing. Instead of "no, n-o", they have typed "k-n-o-w", and I was wondering if it would possible to simply provide a typed list to the transcribers and they could attach that as an errata to the sheet or whether you wanted to read it into the record?

THE CHAIRMAN: They have been doing that occasionally already. They have been putting at the end of daily transcripts errata from previous transcripts.

MRS. FORMUSA: Those would be simply typographical errors.

THE CHAIRMAN: Like the "no/know" ones, for example, is one.

MRS. FORMUSA: There are other matters which the witnesses have identified which they feel need to be corrected. And I wondered how you wanted to...

THE CHAIRMAN: You mean they were incorrectly transcribed?

MRS. FORMUSA: No. In one case, I know the witness said "hydraulic" and meant "fossil." In other cases, I think it may be more substantial and you may want to --

THE CHAIRMAN: And they sometimes get moving to the left and moving to the right mixed up, and things like that.

MRS. FORMUSA: And I wonder if we could do that after the lunch break and we can do it by transcript page.

MS. PATTERSON: Is this something they said wrong?

MRS. FORMUSA: I think they are things that they said wrong.

MS. PATTERSON: Then the transcript is accurate.

MRS. FORMUSA: Yes, it is. And these are matters that they would like to correct because having looked at it, they have made a mistake.

THE CHAIRMAN: They are just slips, like once they said the left and they meant right, things like that, which I think are common enough. Why don't we deal with them after lunch then?

MRS. FORMUSA: Can we do it then?

THE CHAIRMAN: Sure.

MRS. FORMUSA: Thank you.

THE CHAIRMAN: How many transcript volumes are we talking about?

MRS. FORMUSA: Just three.

THE CHAIRMAN: Could you give us the numbers.

MRS. FORMUSA: Yes, Volumes 16 and 17. Sorry, I don't have any to 18, just two.

THE CHAIRMAN: Just 16 and 17?

MRS. FORMUSA: Yes.

THE CHAIRMAN: Well, then the parties should bring, if they have them, Volumes 16 and 17.

Mr. Watson, I guess this would be all involved within your cross-examination, won't they?

MR. WATSON: I would assume so, Mr. Chairman. We had a similar issue arising in Panel 1, and I believe you attempted to draw a dichotomy between corrections. As you said, something that is left and right, as opposed to, in effect, reviewing --

THE CHAIRMAN: That's right, but I mean --

MR. WATSON: This panel wasn't here at this time and perhaps you could go through that dichotomy again.

THE CHAIRMAN: Going through the transcripts, there have been some clear errors, of the nature that Mrs. Formusa mentioned, like, for instance, the word "no" is spelled "k-n-o-w" in one place, and in one place, they say curve moves to the left when, clearly, they meant it to move to the right; things like that.

MR. WATSON: I have, clearly, no objection to that, Mr. Chairman.

THE CHAIRMAN: And once, I think, they used the same heading for both sections and they meant to make a distinction, that kind of thing.

MR. WATSON: Again, we have no objection with that. It's the dichotomy you were talking about in Panel 1 --

THE CHAIRMAN: If we run across any like that, we will have to deal with it as it comes up.

MRS. FORMUSA: Perhaps I could speak to Mr. Watson--

THE CHAIRMAN: Surely.

MRS. FORMUSA: --at the lunch hour and and we can sort them out.

THE CHAIRMAN: Surely. Because they are all in his cross-examination.

MRS. FORMUSA: Yes.

THE CHAIRMAN: All right. I also have to note for the record that, since yesterday, there has been a new exhibit filed; it is marked as 155.

It is entitled "An Independent Review of the Ontario Hydro Demand/Supply Plan Hearing." The author, Olaf Nigol, N-i-g-o-l, dated May 6, 1991.

---EXHIBIT NO. 155: An Independent Review of the Ontario Hydro Demand/Supply Plan Hearing, by Olaf Nigol, dated May 6, 1991.

THE CHAIRMAN: Mr. Rodger?

MR. RODGER: Thank you, Mr. Chairman.

RONALD TABOREK,
DAVID BARRIE,
JOHN KENNETH SNELSON,
JUDITH RYAN; Resumed

THE CHAIRMAN: Do you have any documents you want to file before you start your cross-examination?

MR. RODGER: Yes, I gave Mr. Lucas a package of materials which consists of interrogatories submitted by my client, plus there is one page which is

a photocopy of Exhibit 6, and those are the documents I will be referring to.

I placed a series of copies of these interrogatories at the table to my left for my friends.

CROSS-EXAMINATION BY MR. RODGER:

Q. Panel, the first few questions are more by way of clarification, and I don't believe you have the photocopy which I distributed to the others. It is from Exhibit 6, which is the plan analysis, and it's page 3-17.

And these two figures, Figures 3-7A and 3-7B show system reliability without new capacity addition and system reserve without new capacity addition. And this is with respect to the median load forecast. And we will see from this figure that, after the year 2000, the unsupplied energy sharply increases, and after the year 2000, the system reserve decreases.

And my client asked in Interrogatory 2.24.3, what the data would be with respect to these charts with respect to the upper load forecast. And the answer that we were provided with basically gave the same figures as shown for the median forecast.

I was wondering if this was just an error on your part? We were assuming that we would expect higher unsupplied energy and lower reserves at the

upper load scenario.

MR. TABOREK: A. No, Mr. Rodger. It was because we had not done calculations under the upper forecast. It wasn't available.

Q. Could we have those? Could you do that calculation for us?

A. Could you just hold a second, because I would just like to consult.

MR. SNELSON: A. I think the answer is that the reserve margin part of the calculation is relatively straightforward and that calculation could be done.

The unsupplied energy part of the calculation, strictly speaking, would require additional runs of the F&D program, additional setting up of data, which would be quite a large task. We are talking about several man-weeks. But it may be possible to do an estimation from the results from the median load forecast to give an indication of what they would be under upper load growth with a reasonable amount of work.

Q. So, I can take two things from that. First of all, that the answer we were provided with, that actually isn't correct, and this doesn't apply to the upper load forecast for the reasons you have given?

A. Yes.

Q. And are you able to do that kind of estimation for us that you have described?

A. I believe we can. It would take a few days.

Q. That would be fine.

And I have lost track of which undertaking this would be.

THE CHAIRMAN: This is 142.

MRS. FORMUSA: Point 41.

THE CHAIRMAN: 41.

MR. RODGER: Thank you.

Q. The next interrogatory in the package I handed out was 2.24.13. And in this interrogatory, we asked you to calculate the amount of sulphur dioxide, oxides of nitrogen, and carbon dioxide that would have been produced in each of 1987, 1988, 1989, and 1990, if coal-fired generation replaced Hydro's nuclear generation.

And as part of your response, there is a chart. And in the second column, the chart is entitled total generation fossil plus nuclear replaced by fossil, in gigawatthours.

THE CHAIRMAN: Sorry. Could you tell me again what interrogatory this was?

MR. RODGER: It is 2.24.13.

THE CHAIRMAN: Thank you.

MR. RODGER: Q. And if we look to that particular column, we will see that, from 1987 to 1988, there is an increase in the gigawatthours, but thereafter, it declines. I am wondering if you could tell me the reason why it declines in years '89 and '90.

MR. TABOREK: A. I believe this will be historical data. And the change of about 13,000 gigawatthours between '89 to '90 is probably mostly a result of purchases, although the purchases were not of that magnitude, but that is one factor explained in the change, in that fossil and nuclear would not have been producing.

...

[10:15 a.m.] And then the '88 to '89, that's a very small difference. I think that's just random change in conditions.

MR. BARRIE: A. I think, again, it's probably purchases playing a role in '88 to '89, as well.

Q. I'm sorry, I didn't catch that.

A. In both '89 and 1990, we made purchases specifically with the aim of reducing fossil generation. Much more in 1990 than '89, but it was evident in '89 to a lesser extent. So, that would explain the small difference between '88 and '89 and the large difference between '89 and '90.

MR. SNELSON: A. The other side of the equation is the giving up of sales. So, from one year, there was sales; in the next year, there was less sales. That has the same effect as in the first year there being no purchases, and in the second year being purchases. Both effects have the effect of reducing the amount of electricity we have to generate from our own plant.

Q. I would like to turn for a moment to the 40-year life of the plants. We asked you about this matter in Interrogatory 2.24.14, and as part of your response, you stated that for any particular unit,

retirement could occur before or after the 40-year period. I know Mr. Watson touched on this the past couple of days, so I don't want to go into great detail. But do I take it from that response that the 40-year life is seen as a median value?

There are going to be plants that are going to have to be retired before that time, and there are going to be plants that have a life after that 40-year time frame; is that fair?

MR. TABOREK: A. It is fair, but, at the same time, I would not like to give the impression that there is going to be a lot of scatter. We are presenting the 40-year life as a very strong median, if you will, the right number to use for planning purposes.

Q. So, it wouldn't be accurate then to say, if it is median value, then half of those plants would be retired before the 40-year period?

A. No. I think the words we used were something like some might last longer and some less than 40 years. It isn't a representation of it as a mathematical distribution. It's a description of a...

Q. Because my question arises from testimony in the past couple of days. I am unsure how the uncertainty as to the exact life of a unit, how

that is taken into account when it comes to calculating the reserve margins, if you have some retiring beforehand.

A. In this case, it is not taken into account at all. All of the assumptions that are used in the F&D model and in the Demand/Supply Plan is the unit ceases operating on its 40th birthday.

We introduced that idea in the context of mathematical analyses of complex systems necessarily have to be simpler, and we are, in effect, flagging that the real world is a dynamic process of decision-making as new information comes along.

This is picking up the point Mr. Snelson made late yesterday.

Q. If I could turn, I have a couple of questions with respect to the Lakeview plant, which was also touched on yesterday.

We asked you about the rehabilitation work in Interrogatory 2.24.15, and as part of your response, you stated that Units 5 and 6 are the only ones, to date, which Hydro has committed to rehabilitate; is that correct?

A. We have since gone on to commit two more units to rehabilitation.

Q. Which units are they?

A. That's Units 1 and 2, I believe. Yes, 1 and 2.

MR. SNELSON: A. That is referred to in the interrogatory.

MR. TABOREK: A. Yes, the same paragraph in the interrogatory.

Q. Yes, you said it was by the spring of '91. That was my next question, actually. Those have been committed, too?

A. Yes.

Q. When was that decision made for Units 1 and 2? It says in the answer, spring of 1991, but was it this month, was it last month, two months ago?

A. I don't know.

Q. Could you find that out for me, please?

A. Okay.

I believe that's 142.42, Mr. Chairman.

THE CHAIRMAN: Thank you.

MR. RODGER: Q. With respect to Units 1 and 2, do you anticipate that those units will be out of service for the 14-month period which you have indicated in the interrogatory I just referred to? The line, three-quarters of the way down:

"Currently a 14-month outage to

rehabilitate Units 1 and 2 as planned, starting in the fall of 1991."

MR. TABOREK: A. Again, I am not sure if there has been a change since that time. I would presume this to be correct and I am not sure there has been a change.

Q. Could you get back to me if there is a change?

A. Yes.

Q. If not, I will assume that that 14-month period is correct.

A. Yes.

Q. When will Units 5 and 6 be back in service?

A. Just one moment, please.

Q. Sure. If I can assist you, you do say in the interrogatory that, at that time, it was expected that June and August of 1991 would be the in-service date.

MR. BARRIE: A. The latest schedule we have for Lakeview 5 is still June and Lakeview 6 - I am reading off a chart - October.

Q. October.

A. I could, perhaps, clarify 1 and 2, as well.

Q. Okay.

A. The idea would be that we would only release 1 and 2 when 5 and 6 are completed. So, they are dependent. Lakeview 1, September, and Lakeview 2, October. But that will depend on Lakeview 6 being complete.

THE CHAIRMAN: That is September/October of what year?

MR. BARRIE: Of this year, 1991.

THE CHAIRMAN: Somebody said 14 months a moment ago. Did I miss something?

MR. BARRIE: That is the expected duration of the outage of 1 and 2.

MR. SNELSON: The 14-month period is the expected duration of the outage of Units 5 and 6, and the dates Mr. Barrie has just given are the starts of those 14-month periods.

THE CHAIRMAN: I'm sorry.

MR. BARRIE: I'm sorry, that's not correct. Not 5 and 6; 1 and 2.

MR. SNELSON: Sorry, 1 and 2. Sorry.

THE CHAIRMAN: So they are starting in September and October of '91, is that right?

MR. BARRIE: That's correct. And they finish November/December of 1992.

MR. RODGER: Q. So, with respect to Unit 5, at least, you were on target. You said June would be the start-up date and you achieved June.

For the August date, you said that was going to be the fall now. Could you tell me the reason why that's been delayed a few months?

MR. BARRIE: A. I don't know.

Q. Would it be possible to find out that information, please?

A. We can, yes.

Q. That would be undertaking 142.43.

And given those back-in-service dates for Units 5 and 6 which we have just been discussing, how long were they out of service?

A. Both were taken out of service in February or March 1990.

Q. And that would be in-service, June and October 1991.

Now, I take it that you would like to do the rehabilitation work in the non-winter months of '90 and '91, if possible?

A. That is correct.

Q. And the reason for this is that you don't want to do repairs when you are heading into your peak season or when you are in your peak season?

A. That's correct.

Q. Now, in the DSP, you indicate that Lakeview will reach its 40th anniversary in the year 2006, I believe I am correct in that figure?

MR. TABOREK: A. Well, if you use the 40-year station average, that is correct, and that's what we do at the OEB for depreciating the station as a whole.

In the Demand/Supply Plan, it was done a little differently. It was on the birthday of each unit and the unit birthdays start in 2002 and they run through to 2009. There is a table in the Demand/Supply Plan listing the unit birthdays, I believe.

Q. So that's the average, the 2006?

A. Yes.

...

[10:24 a.m.] Q. In order for all eight units at Lakeview to operate at 2006, I take it for that to occur, all eight units are going to have to be rehabilitated at some point?

A. Yes. With the proviso that there is a relationship between the reliability with which they operate, the amount of money spent on them, and the life that they get to.

Q. Now we have talked about Units 1 and 2, and 5 and 6. How about Units 3 and 4 and 7 and 8? In your response to the interrogatory I referred to, you said that a decision respecting Units 3 and 4 and 7 and 8 is expected in late 1991 or early 1992, following your review and assessing your needs. Is that still correct?

A. Yes.

Q. And can you give us any indication about what decisions will be made with respect to 3 and 4 and 7 and 8? Have you started that analysis?

A. The analysis is started, and what we are doing is looking at a number of alternatives for Lakeview. And the alternatives include continuing with the existing type of rehabilitation, moving to a life-management type of process, in which the rehabilitation is, in effect, done with additional

normal maintenance over the life of the station rather than at one period in time. We are looking at defining different repowering alternatives.

Q. Could you expand on that phrase, please?

A. Well, in that circumstance, some or all of the existing station might be replaced with new components. So, for instance, a combustion turbine might replace the steam boiler -- or the furnace, and various uses could be made with the steam. And there are various combinations of that type that can be considered. Those are the alternatives that come to mind for me.

MR. SNELSON: A. The repowering option would lead to the use, probably, of natural gas as a fuel, rather than coal, for some of the units.

MR. TABOREK: A. That's right. There are various refueling options of different types adding natural gas, in whole or in part.

Q. So, I take it as part of this analysis, when you are looking at these alternatives, you are also looking from the point of view of what the cost is and how the cost of the different alternatives compare to one another?

A. Yes.

Q. When do you think that analysis will be completed?

A. The best information is late this year, early next year.

Q. Would it be fair to say that if the decision is not to rehabilitate Units 3 and 4 and 7 and 8 at Lakeview, then the likely result is higher forced outage rates for those units?

A. Yes.

Q. And can you give me some indication of to what extent the lives of those units, that's 3, 4, 7, and 8, will be shortened, if Hydro decides not to rehabilitate them?

A. Well, I think at the moment you can't give that answer because it depends on what we do decide to do with them. And I believe, personally, that the answer of doing nothing whatsoever is not a tenable answer. Something will be done. And so I can't answer that, until I know what is going to be done, which of those alternatives will be taken up.

Q. Just so I can get some kind of indication. Although you say you wouldn't, or it is likely you wouldn't make the decision not to do anything, if that were the decision, could you then give me some indication of how those unit lives would

be shortened?

A. That is too hypothetical a question to answer.

Q. Whatever decision you do make regarding these other units, how is that decision factored into the reserve requirement analysis, given what we have talked about in the F&D model and so forth?

A. Which particular analysis are you referring to?

Q. When you come with your final result of your 24 --

A. Oh, yes. In the Exhibit 87?

Q. That's right.

A. In Exhibit 87, we used the 1989 reliability indices, the forced outage rates appropriate for Lakeview, and at that time, the assumption was that all eight units would be rehabilitated.

Q. And now if that changes, I take it that these different alternatives are going to have different impacts on the life of those units we talked about?

A. Yes.

Q. So, I am wondering, should you

decide, for example, to repower the units, if that's the decision you make, how that is going to be reflected in that analysis in Exhibit 87?

A. Much of the work we do, we repeat the work annually or periodically. And as new information about a particular event comes about, we incorporate the new information into the analysis.

Q. In the past, when you have done the reserve margin analysis, have you had to face these similar alternatives of repowering and life management and so forth? Or is this kind of breaking new ground?

A. No. This is a new situation.

Q. So, there is, again, kind of another uncertainty of how this will fit into the model?

A. Well, another uncertainty, yes. Well, it is clear how it will fit into the model. When the information is there, we will put it in.

But every time we do the analysis and we review all of the parameters that enter into it, every one of them has an uncertainty of one type or another associated with it.

And I think it is fair to say that every time we do the analysis, there will be some new issues that we have to assess and incorporate and some old ones, and so this is a routine aspect of doing this

analysis.

Q. Perhaps that was a poor choice of words on my part. Perhaps more correctly I should have said there will certainly be an uncertainty to the result of what these inputs or the alternatives will yield. That might have been a better way to put it.

A. Will yield. Well, the yield, if I am now interpreting yield correctly, if an event occurs that puts up the forced outrage rate of a particular generator, it would cause the reserve margin to go up and vice versa, of course. So, the yield, directionally, is pretty well known, yes.

MR. SNELSON: A. That effect would be taken into account in the analysis of the Lakeview alternatives. So when a decision is being made on what to do at Lakeview, and different alternatives have different forced outage rates associated with them, then an allowance would be made in that analysis for that effect.

Q. I see.

Now, Mr. Watson discussed with you a DAUFOP quite extensively yesterday, and I just have one additional question, and it stems from Interrogatory 2.24.20. And it should be page 2 of the response under the chart "Performance Indices - DAUFOP 1980-1990."

And if we look through the various numbers, with respect to Lakeview, Lambton, and Nanticoke, we will see that the DAUFOPs at Lakeview have been uniformly high from 1982 to 1990, when compared with Lambton and Nanticoke.

I know yesterday you mentioned the age of Lakeview, and I am just wondering, is that the sole reason why there would be this difference in the numbers compared to the Lambton and Nanticoke? Why the Lakeview numbers are so much higher?

MR. TABOREK: A. The attribution of a cause to damage is difficult. We know the damage is there. We don't necessarily know why it is there. Age is a reasonable hypothesis. The fact that it tends to peak more, to come on and off more, the thermal cycles, that's a reasonable hypothesis compared to Lambton.

MR. SNELSON: A. There is another factor. And what Mr. Taborek has said is correct. But, also, in the early 1980s, load forecast projections were lower than they are today, and the expected use of Lakeview was less than it has been. And decisions were made to do limited amounts of maintenance on the Lakeview plant. And so to the extent that more maintenance can provide improved performance, then conscious decisions were made to do

limited amounts of maintenance.

The discussion of the details of that, I think, would be better with Panel 8, who would be familiar with the actual details of the plant.

Q. Am I correct that Lakeview was built in the early 1950s?

A. No.

MR. TABOREK: A. No.

Q. When was it built?

MR. SNELSON: A. Lakeview came into service from about 1962 to about 1969.

Q. And was it built as a base load plant or for peak?

MR. TABOREK: A. All of our coal-fired plants were built as intermediate in peaking plants, with all of these specifications.

Q. Now I understand that Hydro has in place systems which are known as load and generation rejection systems; is that correct?

MR. BARRIE: A. Yes.

Q. And if I understand it correctly, you have these systems in place, because, occasionally, there is too much power flow running through the lines after the loss of a transmission element. Is that roughly what the situation is with respect to these

schemes?

A. We have load and generation rejection schemes to cater to the situation after a contingency occurs. It may not be that another line is overloaded. It may be some other system situation exists that we don't want to occur such as very depressed voltage levels, but essentially, yes, you are protecting against a contingency occurring and that resulting in a system situation that we want to avoid.

Q. How does the load rejection system contrast with the generation rejection system? Maybe you could just briefly describe each of them.

A. The generation rejection scheme is associated with an area that has an excess of generation after a contingency occurs. So, if a transmission line trips from a station, this would cause the other transmission lines carrying power from that station to be overloaded or some of those other circumstances I described.

So, essentially, what happens is that the scheme will automatically remove generators from the system immediately the trip occurs. A load --

Q. Sorry, go ahead.

A. A load rejection scheme is really the reverse of that. This is in an area where there is

insufficient transmission into an area, so that, if a contingency occurs, the remaining lines would be unable to supply the load in that area.

Q. And would an example of that be the problems at Bruce where you had...

A. Bruce is a special case, if you will. The Bruce Special Protection Scheme is essentially a generation rejection scheme, but it is of such magnitude that it has load rejection also associated with it. So, perhaps I could explain why that's necessary at Bruce, because it is rather a unique situation.

Q. Okay.

A. In my direct evidence, I discussed how the loss of certain 500 kV lines out of Bruce would result in a requirements to reject up to four units of generation. That is a very large rejection. That is an order of magnitude bigger than rejection almost anywhere else, so we are talking about a very special case here. We could reject over 3,000 megawatts of generation.

...

[10:40 a.m.] When that occurs, if nothing else was done, there would be an in-rush from the tie lines, from our neighbouring utilities of 3,000 megawatts, or very nearly 3,000 megawatts, to make up that lost generation. That would be an unacceptable situation.

So, we have agreed with our neighbours that we would limit the tie line in-rush, as we call it, to 1500 megawatts. What that entails then is that we have to reject up to 1500 megawatts of customer load, at the same time as we reject the 3,000 megawatts of generation to limit the tie line in-rush to 1500 megawatts.

So, the generation rejection is all at the Bruce complex, the load rejection is everywhere else in the province.

Q. So there is no other generation rejection except for Bruce; is that right?

A. No, there is other generation rejection.

Q. Okay.

A. There is nothing of that magnitude, and there is nothing that involves that kind of simultaneous rejection of load to limit tie line in-rush.

The other rejections tend to be talking

about hundreds of megawatts rather than thousands of megawatts.

Q. Am I correct when I say that new high voltage lines should help this problem a long way?

A. Reinforcing the transmission is the best long-term solution to generation on load rejection requirements, yes.

Q. My client asked you about these matters in Interrogatory 2.24.10, and as part of our question, we asked you to describe how long these load and/or generation trip schemes are expected to remain in regular operation. And as part of your answer you said, near the bottom of the page:

> "The use of these schemes will continue to be required during forced and planned outages."

I wonder if you could give me an indication of which of the schemes will still be required after 1992, and I believe that's after a lot of the new transmission lines will be in place?

A. Do you want me to go through all 16 rejection schemes?

Q. With respect to that question, please.

A. The Beauharnois generation rejection

scheme will be required indefinitely; the Bruce load and generation rejection scheme will be required indefinitely; Chenaux/Mountain Chute generation rejection scheme will be required indefinitely; the Darlington generation rejection scheme should no longer be needed with the reinforcement of the Bowmanville-Cherrywood 500 kV; the Dobbin load rejection scheme should no longer be required after 1992, when transmission reinforcements are put in place.

There are a number of the next ones -- well, I will take them one at a time.

The transmission in the Northeastern Ontario is planned to be reinforced over the long term, between the year 1992 and the year 2000. One of the by-products of that will be to remove the need for the Dymond load rejection scheme. That's No. 6.

The Flow East Toward Toronto LGR scheme is rarely required.

Q. Rarely required, but it will still be in place, I take it, after '92?

A. That's my understanding, yes.

The Lambton generation rejection scheme will be remain in place indefinitely; the Lower Notch generation rejection scheme, that's like the Dymond

one, when the Northeast is reinforced, as is the Moose River; the Nanticoke generation rejection scheme should no longer be needed after 1994; the NorthWest load rejection scheme will be rarely needed, when we are in the position that we are in now, with a firm purchase from Manitoba Hydro, and the installation of non-utility generation up there would also help. We envisage the scheme will be still be in place, but not needed very often.

The Ottawa load rejection scheme will rarely be needed from November 1992, with the 500 kV reinforcement; the Otto Holden generation rejection scheme, again, when the Northeast transmission is improved, it will be no longer needed; Stewartville generation rejection scheme will be required indefinitely; the Windsor Area Overload Protection and L/R scheme will be no longer needed after 1996.

Q. So, although the new lines are going to improve the situation substantially, it would seem, there is still going to be some key areas where the system would still be required to be in place?

A. I think the transmission reinforcements solve the major problems. The ones where it is not solved is because it's not deemed to be cost beneficial to do so.

Q. And what makes it not cost beneficial?

A. Many of these schemes are only armed for a very small percentage of the time. Some specific system circumstance requires them to be armed. If they are very rarely armed, then it's not worth spending a lot of money to rectify the situation.

Other ones, although they may be armed, other ones may be armed more often, the consequences of them being armed is not great on the whole system anyway. That is, there is not a great amount of load or generation being rejected.

So, again, this would be a judgment as to whether it's worth spending a lot of money to rectify the situation.

I think those are the two factors.

Q. Thank you.

Now, I understand that another problem on the Hydro system is also the high short-circuit levels, particularly around the Toronto area; is that correct?

A. High short-circuit levels are a problem, yes.

Q. And could you give me a brief overview of what the problem is?

A. I should explain what the phenomena

is first?

Q. Please.

A. When a fault occurs on the electrical transmission system, the fault is fed by all circuits connected to that piece of apparatus. The fault current is dependent upon the amount of generation, and the amount of transmission in the vicinity of that particular fault.

As one adds more generation in transmission, the fault current increases. All circuit breakers have a rating, a fault current interrupting capacity. On our 230 kV transmission facilities, that's 68,000 amps. At some parts of our system, we are exceeding that rupturing capacity.

Q. And I understand that, and I believe it's from your plan analysis when you are describing this phenomenon, you say that these levels are now approaching the point where they are among the highest experienced by any utility world-wide. Is that correct?

I believe I might be able to get the --

A. I am not sure how we compare to other utilities. I am sure there is other utilities with just as high, but I am not an expert on international short-circuit levels.

Q. I think it's a on page 5-6 of the plan analysis. I don't want to the misquote the document, so let me just check that.

Yes, it's the last paragraph, about eight lines down.

THE CHAIRMAN: What page, please?

MR. RODGER: 5-6 of Exhibit 6, the plan analysis.

Q. And you described the situation and then there is the sentence:

"These levels are now approaching the point where they are among the highest experienced by any utility world-wide."

MR. BARRIE: A. Well, I have operated systems that are considerably higher. The United Kingdom has a considerably higher short-circuit level than experienced in Ontario.

Q. One way that Hydro deals with this problem, as I understand it, is to split stations?

A. Yes.

Q. Could you just describe for me what is involved in that process?

A. Well, as I said, if a fault occurs, say, at a particular station, then all the transmission connected to that station, if the bus-bars at that

station, if the switches are all closed --

Q. Maybe you could just tell me, sorry to interrupt, what a bus-bar is?

A. Okay. The transmission lines that come into every station, there are a series of circuit breakers and conductors, whereby the lines can be configured so that power can go wherever we want it to. That is, we can arrange the system so that you can regard a station as being a solid, just as if it was one lump of conductor. When I talk about a bus-bar being solid, that's what I am referring to.

But we have switches, circuit breakers at the stations, which allows us to separate the station so that it's essentially two stations. We call those the bus tie-breakers, which connect two pieces of conductor which we call the bus-bars.

So, one way of solving a short circuit, the high short-circuit level, is to open those bus tie circuit-breakers, so that if a fault occurs, the circuits that are on the other side of the break will not feed into the fault. This is what we have to do operationally. This is all we have at our disposal in the operating time frame to solve the problem if it gets too high, if the short-circuit level gets too high.

Q. In Interrogatory 2.24.11, we asked you a little bit about this phenomenon, this problem, and as part of your response at the bottom of the page, you say that this growing complexity can reduce operational flexibility, increase operation facility costs and reduce the level of security of the bulk electricity system.

Can you expand on that? I would like to know how it reduces operational flexibility and what happens when you do have a lot of these split buses on your system?

A. If we take, perhaps as an example, Lakeview, Lakeview generating station, because of high short circuit levels, if we have only one machine on at Lakeview, the short circuit levels are low enough that we can run with no splits, that is, the bus-bar aside.

...

[10:55 a.m.] As we synchronize machines at Lakeview, the Lakeview bus-bar short-circuit level increases, and we have to split. The Lakeview bus-bar is, in fact, a ring main. The bus-bar is a ring with circuit-breakers in the ring. So, we can open two circuit-breakers and split the ring into two, and we can do it in various ways.

Once you do that, once you make that split, then should -- first of all, speaking about operating flexibility. This can cause us not to be able to put on any units we like. We have to put certain units on on one side of the split or the other side of the split. When it is all one bar, then we don't need to be concerned.

But we have certain transmission facilities emanating from Lakeview. We have to be sure that we have adequate transmission into each side of the split. Basically, it is just an added operating complexity that we have to take account of in deciding which units to put on, what the feeds, transmission feeds, are in and out, the voltage levels. All of that has to take account of a new situation now, where we split the station in half, rather than running it as a single entity.

Now, I should say that we have not been

able to identify any examples of where these splits have caused any interruptions to customers or any unsupplied energy. So, it is an issue that is of concern to us, but it is not one that has been reflected in the performance of the bulk system in terms of unsupplied energy.

Q. Would it be fair to say, though, that by splitting major stations into two or more, that makes the system more unreliable because, in essence, you are lowering the limits placed on those transmission facilities; like, for example, the Flow East to Toronto?

A. No, that is not a good example.

Q. How about the premise, then?

A. The basic premise. When you split a station, you are basically removing some of your redundancy. If you have four circuits feeding a station and you split it in two, so that you have two circuits feeding each half, then, clearly, that is inherently less reliable, because if you lost the two circuits on one side, you would lose supply to one side of the station. Whereas, if you were running with the station as one station, then you would still, if you lost two, you would still have two supplying the rest of the load.

So, it is inherently less reliable to be split. But I want to emphasize that this has not caused us any major problems at this point in time.

Q. Will the short-circuit current levels, will those continue to be a problem on the existing system and into the future?

A. Yes.

Q. If could I ask you one more question on this topic. What effect does the splitting of stations, what effect does have have on the load rejection and the generation rejection schemes that we just talked about a minute ago?

A. None of the five stations that I quoted as requiring splits, Lakeview, Manby, Cherrywood, Leaside or Richview, would affect the generation load rejection schemes that I just described. I don't see any connection.

Q. I will leave that for now.

In your direct evidence, you talked a little bit about power pools, and I understand from that evidence that one of the key benefits of being within a power pool is the individual utilities share the risk of inadequate power versus if that utility was out on its own. Is that fair?

A. That's fair for a power pool. It's

also fair for any interconnected utilities.

Q. Okay. Building on that, you stated in Exhibit 87 that for Hydro to establish its reserve margin in that overall analysis, it's more appropriate to compare Hydro with a power pool than with a single small utility. And I am wondering, do you use that comparison with a power pool solely on the issue of the size of Ontario Hydro?

MR. TABOREK: A. Yes. And the fact that the particular pools we chose were thermally based to make them like us.

Q. Is it a fair statement to say that utilities which make up power pools, they have diversity of loads between them?

A. Yes.

Q. And maybe you could just describe that first of all. What do you mean by diversity of loads?

A. It means that if I am Utility A, I may have my peak load on January 15th, say, and Utility B may have their peak load on January 31st. If you just add up all the peak loads, you would get a larger number than if you add up my peak load on January 15th and Utility B's smaller peak load, and so what you are looking for is a coincident peak, in effect.

The value of diversity we have heard reported, variously, as being worth from 1 to 5 per cent of reserve margin. And what that means is that, if a group of utilities enter into a pool, each individual utility can have a smaller reserve margin by virtue of the fact of being in the pool.

Q. Has Hydro done any analysis to determine whether load diversity exists in your system like it does in the power pools that you are comparing Hydro to?

MR. SNELSON: A. I believe there is some diversity analysis that is done with respect to rate making, because of the use of peak loads and non-coincident peak loads as measures for rate making. That's discussed in front of the Ontario Energy Board and we are not familiar with that.

I think we are familiar that, in a general sense, there is diversity between loads; that some parts of the province tend to have loads higher in winter than in summer, and other parts, such as Toronto, tend to have loads that are higher in summer than in the winter. Did I get that right way round?

Some parts are winter-peaking and some parts are summer-peaking, and so that clearly is diversity between different parts of the system.

Q. I will tell you what I am driving at. I was a little unsure of whether that was a fair comparison of Hydro and power pools, because if you haven't found diversity of loads in your system, then isn't the result of comparing Hydro with power pools, you're biasing the reserve margin downward, because you are getting the benefit of a lower reserve margin by comparing yourself with a pool, but you may not have that diversity of loads like power pools, true power pools, do? That is my concern.

A. I think that if you say that the New York power pool is one of the pools we compared ourselves to, then there are a group of small utilities who form the New York power pool. Some of them are downstate and include New York City; some of them are upstate and include places like Buffalo and Rochester; some of them are mainly suburban utilities with not very much industrial load.

So, there is a variety of loads and locations to the loads, and the total diversity within that region is probably comparable to the total diversity within Ontario, taking into account cities such as Toronto, and southern areas' and northern areas' rural and industrial loads. We have a comparable mix to the whole of the New York State.

Q. So, you're comfortable with that comparison, and my suggestion that, by comparing it, you might have biased the reserve margin downward. You would disagree with that, I take it?

A. We think that the comparison to the power pool is more appropriate in the comparison to any one of the constituent utilities.

Q. Perhaps you can answer my question, Mr. Snelson. Do you disagree with my statement that this comparison runs the risk of biasing the reserve margin downwards?

A. We think we have chosen the right comparison.

Q. Panel, if you could have Exhibit 87 handy and, Mr. Chairman, I am going to be referring to it a number of times from here on in. On page 66 of Exhibit 87, which is the review of generation reliability planning criteria.

THE CHAIRMAN: Sorry, which page again, please?

MR. RODGER: 66.

Q. And on that page, Table 4-1, there are reasons for bad year reliability. And I understand that that table is based on a survey of utilities for the California Energy Commission. Was Ontario Hydro

part of that survey?

MR. TABOREK: A. No.

Q. Do you know how "bad year" was defined in that survey?

A. In general, a year in which they were concerned about reliability; the precise criteria, I do not know.

Q. Could you find that out for me, please?

A. Yes.

Q. I believe that makes it Undertaking 142.44.

My next question might be premature since you are not sure of the definition. I was wondering, based on this definition of "bad year," whether Ontario Hydro has experienced a "bad year" in the past ten years?

A. We have, earlier in our testimony, described 1989 as a bad year, and the criteria which we used was the occurrence of the use of emergency measures significantly above the past.

Q. Perhaps I could ask you, given that the Demand/Supply Plan which is before the Board, which is a 25-year plan, and given the 24 per cent reserve margin, could you tell me what the probability is of

Hydro's standard of 25 system minutes of unsupplied energy being exceeded?

THE CHAIRMAN: Did you say 25 minutes?

MR. RODGER: Yes.

MR. SNELSON: I don't think the calculation enables us to estimate the probability of its being exceeded in any particular year or not, directly, anyway. 25 system minutes in the old calculation, or the 10 system minutes in the new calculation, is the expected value, assuming that you plan on the level of reserve that we are recommending.

MR. RODGER: Q. So, you can't say that it won't happen, but you haven't done any --

MR. SNELSON: A. Our sense is it is an expected value, then it is made up of some years which are higher and some years which are lower. And the general characteristic is that there tends to be a few years when it is very high, balanced by a much larger number of years when it is quite small.

Q. So, you couldn't give me an answer as to the probability?

A. No.

Q. If you could turn to page 18, please, of Exhibit 87. And on that page you identify a number of key variables in the load model and the generation

model. And you preface this list of variables by saying "Some of these are..." and you go ahead to list them. Could you tell me what other variables exist, which are not included in those lists?

MR. TABOREK: A. I believe the description of the hydraulic system, if I haven't...

Q. This is under the load model?

A. Under the generation model.

Q. I'm sorry.

A. Are we talking only about the load model at the present time?

Q. I would like to hear from both of them, but the order is up to you.

A. I think these are the broad categories, the factors that are modelled. Actually, there is some...

Q. I was just concerned when, at the top of page 18, you state, "The model includes a description of the key variables. Some of these key variables are..." I guess I was concerned that there were some important ones that were not included for some reason.

A. Excuse me for one moment, please.

I think what the wording is meant to describe is that we seek to identify the main factors

related to load, and then we write mathematical models that attempt to describe them. The models are again descriptions, a mathematical description, of a complex reality and, of nature, of necessity, a simple description.

So that you would get, for instance, the fact that on the hour-to-hour and day-to-day variation in loads, every weekday would be the same, for instance. You would get limitations in the descriptions we are making. But when I think through the main factors that we have in our model, these are pretty well covered on the load side.

MR. SNELSON: A. I can't see any key ones that are missed.

Q. And for the generation model you mentioned hydraulic. Is that the only addition?

A. The hydraulic is indicated in the last paragraph on that page.

...

[11:15 a.m.] MR. TABOREK: A. Yes, okay, it's mentioned in the last paragraph. And for instance, here, you would have common cause outages.

Q. Okay.

THE CHAIRMAN: Common cause outages are modelled in the F&D?

MR. TABOREK: No, they are not.

THE CHAIRMAN: Well, I thought this is saying what is included.

MR. TABOREK: I'm sorry, I thought I was answering the question, "What factors are not included in the model?"

MR. RODGER: No, I am sorry.

Q. At the top of page 18, you say the model includes a description of the key variables?

MR. TABOREK: A. Yes.

Q. Then you say, "Some of these variables are..." I am wondering what variables are key but which you didn't include in this list on page 18.

A. Then again, these are the key factors again in the model on the generation side.

Q. Okay. Can you give me a sense of which of these variables listed on page 18 are the more dominant in determining the reserve level required to

meet the 25-system-minute standard?

A. Generally, you are looking at things that can happen to load, things that can happen to generation than are different than your plan.

The two models, or the one factor that is traditionally modelled first, because it is very important, is forced outages. Another factor which is very important is the load forecast uncertainty.

Now, going beyond that, as those are the two first large factors, I don't think I am comfortable to attempt to discriminate further in order of importance.

Q. That's helpful.

MR. SNELSON: A. I think we have already testified to Mr. Watson that repair times are very insignificant.

Q. Thank you. Could you turn to page 110, please, of Exhibit 87? Perhaps I could start on page 111.

Table 6.8 shows the historical forced outage factors for 1985 until 1990, on a system-weighted basis, for both nuclear and fossil plants. When you have here forced outage factors, is that the same as forced outage rates?

MR. TABOREK: A. Yes.

Q. In that chart, the forecast for nuclear has been omitted--

A. Yes.

Q. --as an average. Why was that? And could you provide that figure for us?

A. We categorize outages by the manner in which they occur, and the categorization is: Are they forced on us, broadly speaking, or do we plan them?

In the case of outages at Pickering 1 and Pickering 2, these retubings were forced on us, we had no warning they occurred. Succeeding retubings, we are planning and, hence, they will not be forced and affect reliability; they will be planned.

Q. But there still could be other factors which result in a forced outage rate for nuclear?

A. Oh, yes, there will, indeed, be a forced outage rate for nuclear as we tabled in our evidence. It is just that it will not include, in the forced outage rate, future retubings. That will be included in the planned outages, factors, the POFs.

Q. On page 110, Table 6.7, you show the planned outage factors, 1985 to '90, for nuclear and fossil. We see that the forecast planned outage factor

is significantly less than the historical average. For nuclear, we have an average of 9 and the forecast is 5; for fossil, it's 16 and the forecast is 12.

And then in the next paragraph, there is a sentence which reads:

"Increasing staffing levels and rehabilitating old plant can influence the planned outage factor."

In the past three years, to what extent has staff been increased at Hydro's fossil stations?

MR. SNELSON: A. I think Panel 8 would be able to help you with that.

Q. Could you tell me about future plans for increasing staff at fossil, or do you want to wait for Panel 8, as well?

A. Panel 8 would have more detail.

Q. Okay.

Now, I understand that a hiring program was put in place by Hydro, in the past three or four years, for Hydro's nuclear plants to increase performance, is that correct?

MR. TABOREK: A. Yes.

Q. How many staff are we talking, approximately?

A. Approximately 1,000.

Q. And has the program been monitored to see whether this increasing staffing level has produced any discernible improvements at the nuclear stations?

A. My understanding is that as you bring staff on board, there is a period of training that they have to go through, and then they are put on to the units to do the required work. And the work is done over a certain rate of time, and that there is a lag, if you will, between when you start the hiring and when you begin to see the results.

Q. What, approximately, is the training period we are speaking of, with the nuclear?

A. And here I would refer you to the nuclear panel.

Q. I take it, that same response applies for the lag time?

A. Yes.

THE CHAIRMAN: What panel is that?

MR. SNELSON: Panel 9.

MR. RODGER: Q. And for future hiring programs for nuclear?

MR. TABOREK: A. Panel 9.

Q. Now, we talked a little earlier on about the major rehabilitation work going on at Lakeview. Has Hydro ever experienced rehabilitation

work at the level of Lakeview? Has it ever experienced that level before, in terms of the magnitude of the rehabilitation?

MR. SNELSON: A. We have rehabilitated generating plants in the past. Keith Generating Station in Windsor was rehabilitated in the late 1970s, but that was only 250 megawatts in total, for four units. So, I think that it is fair to say that Lakeview is a larger scale rehabilitation than we have been into in the past.

Q. What were the results of the rehabilitation at Keith? How did that rehabilitation turn out, in terms of an increased life? I just want to get some kind of feel of what the results have been, based on your experience.

A. The plant was put back into service. At about the time it was coming back into service, we were into a situation of very high reserve levels, as a result of loads being less than forecast - and I am talking the early 1980s here - and the plant was not required for Ontario needs. And for a short while, it was sold to General Public Utilities. And after that period, it was shut down. I don't think it was operated for long enough to be able to form a view as to the ultimate effect on its life.

Q. If I can refer back to that statement on 110 about increasing the staffing levels and rehabilitating old plants can influence the planned outage factor.

Are you aware of any evidence from any other utilities that support this statement? Are you looking to other experiences that you are relying on when you say this?

MR. TABOREK: A. I think it is a statement of logic.

THE CHAIRMAN: I'm sorry, I didn't hear that.

MR. TABOREK: I believe it's a statement of logic.

MR. RODGER: Q. As opposed to looking to other utilities?

MR. TABOREK: A. We certainly did not do an analysis of other utilities' experience. It was a point of, if you did a significant amount of work now, then you would expect to do less planned work in the future.

MR. RODGER: Mr. Chairman, I am going to be starting on a new area. Would you like to take the morning break now?

THE CHAIRMAN: Yes, we will take the

morning break now.

How are you doing?

MR. RODGER: I am actually doing very well. I think that I am about a third of the way through.

THE CHAIRMAN: So, should we get Energy Probe ready to start this afternoon?

MR. RODGER: It is possible that I could be finished shortly after the afternoon break.

THE CHAIRMAN: All right. Thank you.

THE REGISTRAR: This hearing will recess for 15 minutes.

---Break at 11:30.

---On resuming at 11:50 a.m.

THE REGISTRAR: This hearing is again resumed. Please be seated.

THE CHAIRMAN: Mr. Rodger.

MR. RODGER: Thank you, Mr. Chairman.

Q. If I could turn to a couple of questions regarding the F&D model. You have said in your evidence that the F&D model assumes that uncertainty in basic demand is not changed as a result of the estimate of demand-side management.

MR. TABOREK: A. Yes.

Q. And from that, I take it, your view

is that there is no correlation between those two variables?

A. That's what we assumed.

THE CHAIRMAN: I'm sorry, I don't quite follow the question. Could you just repeat that again?

MR. RODGER: Well, Mr. Chairman, in Exhibit 87, Hydro stated that in their analysis, in the F&D model that they use, the uncertainty in basic demand, that's not going to be changed on the effectiveness or ineffectiveness of demand-side management programs.

THE CHAIRMAN: But I thought they were dealing with the primary or firm load which already takes the demand-side management into account.

MR. RODGER: But not for basic, not in terms of the basic load forecast.

THE CHAIRMAN: No, but I thought they did their F&D modelling on the primary and firm load. Am I wrong about that?

MR. SNELSON: That's correct.

MR. TABOREK: You are correct, sir. The issue is, what we do is we start with basic, we subtract demand management, we go to primary.

THE CHAIRMAN: You don't do that. Do you do that? Are you the people that do that?

MR. TABOREK: Well, at one step or other in the process, it's done. The estimates are given to us by Mr. Burke. In this particular instance, we now had to ask Mr. Burke another question as to what the uncertainty was in demand management and whether, as Mr. Rodger has asked, there was perhaps some correlation; namely, if we were on the high side of our demand estimate, might we be on the high side of our demand management.

First of all, if we were on the high side of our basic estimate, might we be on the high side of our demand-management estimate or vice versa, i.e., is there a correlation? And after considering several possibilities, the final judgment was just to use what we described. That, in going from the basic to the primary, the megawatts of uncertainty remain the same.

THE CHAIRMAN: Fine. Now, what is your question about that?

MR. RODGER: Q. Following from that, you also acknowledge, in Exhibit 87, that the impact of your demand-side management programs, that depends on the decisions made by, your words were, hundreds of thousands of consumers and, therefore, is uncertain.

MR. TABOREK: A. Yes.

Q. And yet in determining the reserve

margin, you used the demand-side management target, if you will, as a fixed figure.

A. Yes.

Q. Could you have treated demand-side management as uncertain, mathematically, in the model? That is, could demand management be expressed in a probabilistic form?

A. With some work, yes.

Q. Now, I want to clarify one point, and this stems from the May 23rd hearing day. Mr. Taborek, you responded to a question from Mr. Watson about whether uncertainty in the demand-side management forecast, whether that was included in the F&D model, and I took your answer to be, it is included, but it doesn't have a big effect.

A. Yes.

Q. Could you first tell me how the uncertainty is included in the model?

A. As I have explained to you, it's assumed that it has no effect on the megawatts, the uncertainty in the megawatts in going from the basic to the primary.

Q. Okay. I will tell you my concern. My concern is that, if you treated the demand-side management programs as uncertain in a probabilistic

form, then if you run that through the model, the result, at the end of the day, would be more uncertainty overall, because you are combining the uncertainty of the basic load forecast and the uncertainty of the demand-side management.

And I am envisaging a scenario where you could be on the upper end of the basic load forecast and yet you could be on the lower end of the demand-side management programs. You could achieve less than what you anticipated.

A. Yes.

Q. I am wondering how that possibility - and it is a possibility - how that works its way through your analysis?

A. Well, as a starting point, you should consider that we are looking at something in the range of 24,000 to 30,000 megawatts of basic in the primary load, so we have a very large number. In that large number, we do ascribe uncertainty. So, on the one hand, you are getting uncertainty of a large number.

Then, when you look at demand management, a number which you are, in essence, going to subtract from the large number, you are looking at a substantially smaller number, in the range of 2- to 3,000 megawatts, and then what you are interested in is

the uncertainty in the small number.

Q. Right.

A. And so the first thing, you had earlier asked me about big effects and small effects, and I said the load uncertainty is a big effect. Well, just logic would say that the demand management uncertainty would be a small effect.

Now then, when you begin to ascribe more in the way -- well, if you attempt to now say, might demand management go down, if load forecast uncertainty goes up, or would it go up? If they go down, are they positively correlated or negatively correlated, or not correlated?

We looked at various possibilities like that and there were two reasons why we did not pursue this further. One, we felt that the assumption we made was the best assumption, the most descriptive of reality. And the second was that, even if you made different assumptions, the effect was quite small. And, therefore, on balance, the assumption which we made was the most appropriate for the purpose.

Q. All right. If we hold that answer for the time being.

These past few questions, they can also be applied to NUGs as well, in that NUGs is also

uncertain?

A. Yes.

Q. Although it is uncertain, Hydro treats NUGs as a fixed value and so, once again, you also have that uncertainty.

A. Well, it would probably be useful to discriminate between the load displacement NUGs and the supply NUGs.

The load displacement NUGs are roughly treated similarly to the demand management, and the same general arguments apply.

...

[11:53 a.m.] We didn't go into as much detail, having gone through the first one. And, of course, the supply NUGs are modelled as generators and the appropriate uncertainty in the generators are ascribed to them.

Q. And to take that one step further. You also include capacity-interruptible load as a fixed value, don't you?

A. Yes.

Q. And again, the same line of questions could apply to that element: The amount of electricity available for interruptions varies day to day, in the years in the future, there may be contractual limits or we don't know how many customers are going to take up that option.

My point is that, if you combine those three uncertainties of demand-side management, of NUG, of CIL, and you do get that situation of high growth, and you achieve lower amounts than you have originally anticipated, then where does that leave you if that situation actualizes?

A. The principle you are describing is correct, but in the case of if you consider the size of numbers again, when we are talking about interruptibles, we are talking about the 6- to 700 megawatt range of numbers. And my judgment is, and the

principle on which we acted was, that those numbers were not significantly affecting the results we were obtaining.

MR. SNELSON: A. There are two factors that come into making the scenario you are suggesting somewhat less probable, and that is that, when load growth is high, then there is more load to be managed, so there is more opportunity for demand management.

And also, as will become apparent later in this case, when load growth is high, avoided costs tends to be high and when avoided cost is higher, then that can have, at least directionally, the effect of tending to increase the amounts of demand management of non-utility generation in the way in which you would wish it to change, i.e., to offset part of the increased load.

So, there are factors that tend to mitigate against the combination of high load and low effectiveness of demand management in NUGs.

Q. Although those additional factors make it no less uncertain what actual amounts you will, in fact, achieve?

A. There is still uncertainty, yes.

Q. Would be it be fair to say that, by expressing demand-side management, capacity-

interruptible load, and non-utility generation as fixed figures in this analysis, you at least run the risk of understating the reserve margin, given these uncertainties that we have talked about? At least that's a risk?

A. I believe that there are others who argue that, by keeping them fixed, they are overstating the reserve margin. And the result of our judgment is that this is the best judgment that we can produce at the moment.

Q. Would you agree that in a planning exercise like the one we are involved with here, it would at least be prudent to run the analysis, as I have suggested, where you take CIL, NUGs, and demand-side management in a probabilistic form, and at least see what kind of results it comes out with?

A. We haven't run that analysis. We did discuss that sort of outcome in the Demand/Supply Plan Report in Exhibit 3. That's discussed qualitatively in a number of cases, where the allowance that is made for load-forecast uncertainty is described as permitting some variability in demand management and non-utility generation achieved amounts to be covered off.

It does acknowledge that it doesn't provide full coverage for high load growth and load

demand management at the same time.

So, the allowance for load-forecast uncertainty covers uncertainty in demand management and non-utility generation, as long as they both don't occur to their full extent at the same time, which is a relatively small probability.

MR. TABOREK: A. And in particular, we didn't think it was important to do it and we didn't do it, after due consideration.

Q. And that analysis that Mr. Snelson just spoke of was not included in Exhibit 87?

MR. SNELSON: A. No. As I say, the qualitative discussion is in Exhibit 3.

Q. I also have a few clarifications with respect to the 4-year lead time. Over the past couple of days, you have indicated how the standard deviation of forecast error is very sensitive to the lead time, and I believe it was Table 4.4 on page 70 of Exhibit 87 which shows how, if you have a longer lead time, the higher the standard deviation is. And as one example, there was a jump, from a 4th to 6th year, from 8.8 per cent to 14.1 per cent, which illustrates this point.

Now, on page 71 - I don't think you have to flip to it - but you state that the lead time for a CTU from commitment to in-service is about 3 to 4

years. And first of all, if Hydro decides it needs to bring a CTU into service, I understand this is done in stages. There is a commitment stage, definition, and acquisition. Is that fair?

A. I'm sorry, I was just reading the context of page 71 and I wasn't listening to your question.

Q. Sure. If Hydro decides today, for example, that it will require a CTU, there are certain stages in which the process would follow. And the stages, as I understand them, there is a commitment stage, a definition, an acquisition. That these are three things --

A. There is a concept phase, a definition phase, and an acquisition phase.

Q. Maybe you could just briefly describe each of those stages, because that's where some of my confusion lies from the testimony of the past few days.

The first stage is commitment, or conceptual, I believe, were your words.

A. The concept phase is the first phase, yes.

Q. What does that entail?

A. That entails, generally, internal engineering studies and environmental studies to look

at a range of alternatives and develop concepts and so on. It's a fairly general stage. It probably wouldn't have much in the way of detailed engineering for any particular site.

Q. How about the definition stage?

A. The definition phase usually starts at about the time that a preferred alternative is identified and work commences to prepare for, and undertake, an environmental assessment of that particular preferred alternative and preliminary engineering of that preferred alternative.

Q. And the acquisition phase?

A. The acquisition phase starts once all approvals have been obtained, and a decision to commit is made, by the board of directors of Ontario Hydro usually, but it may require confirmation, in most cases, it will require confirmation by Order of Council of the provincial government.

And essentially, once commitment has happened, then orders can be placed, construction work can start, and all the processes that lead to the construction and, eventually, service of the facility can proceed.

Q. Did you say just now that the orders can be placed in the acquisition stage?

A. It is not normal to place orders prior to commitment. If any orders were placed prior to commitment, they would have to have cancellation clauses in case the commitment did not, in fact, happen.

Q. Okay. Now Mr. Watson asked you how you arrived at this 3- to 4-year lead time, and I believe it was Mr. Taborek's evidence when he said, "It is the result of discussions with Hydro's engineering and supply departments and with discussions with the suppliers." Is that an accurate recollection of your evidence?

MR. TABOREK: A. I think, essentially, except I said that I believe that the engineering and supply departments had discussions with suppliers.

Q. Were these discussions, are they documented anywhere?

A. Not that I am aware of.

Q. So, there is no inter-office memo from one supplier to Hydro and from within Hydro to your group? No?

A. Not that I am aware of.

Q. So, when you stated that this lead time resulted from these discussions, it's based, then, on just verbal discussions that, not yourself but other

people in your group or in Hydro's engineering, have --

A. Well, where in particular we got our information from is in the Demand/Supply Plan. And this information is in Chapter 15, I believe you said, Ken?

MR. SNELSON: A. Yes, it is figure 15-6 on page 15-6 of Exhibit 3.

MR. TABOREK: A. Not of the analysis. Oh, sorry.

Q. Can you tell me which suppliers were contacted?

A. I would suggest you refer this to the panel that will be dealing with that subject.

MR. SNELSON: A. Panel 8.

Q. Panel 8.

Now, when you were giving evidence regarding meeting the 4-year lead time, Mr. Snelson stated that, assuming that all approvals had been given. And do I take from that, that when Hydro decides it needs a CTU, it doesn't require a further environmental assessment for that CTU, that this proceeding encompasses the CTUs envisioned in the Demand/Supply Plan?

A. Can you repeat that, please, Mr. Rodger?

Q. In discussing how you were going to meet the 4-year lead time, it was your evidence that you said that you could meet the 4-year lead time, assuming that all the approvals have been obtained.

And I am wondering whether, when Hydro decides it needs a CTU, does it believe that it won't have to proceed to another environmental assessment for that CTU; that is, that this environmental assessment hearing will cover all the CTUs that may be anticipated in the Demand/Supply Plan?

A. We expect the CTUs to have to have two stages of environmental approval: The approval of rationale and need in this process and the approval of site-specific matters, siting selection and site-specific environmental impacts and so on, as part of a second-stage process.

Q. Does that site-specific process, the site-specific environmental assessments, does that include a situation where Hydro wants to put in a CTU at one of its current generation sites?

A. Current generation sites have been identified as potentials for combustion turbine units.

Q. And along with that, do you foresee an environmental assessment required if it is with a Hydro site?

A. That might depend upon the circumstances.

Q. So, it could be yes or it could be no?

A. We always have to meet the requirements of the Environmental Assessment Act, and I don't want to get into the area of law here.

MRS. FORMUSA: Perhaps I could be of assistance here. There are a number of exemption orders that Hydro has, which would have an impact on whether on environmental assessment is required at an existing facility. And in particular, there is one with respect to combustion turbine units.

But, generally, what Mr. Snelson has said with respect to the two approvals that need to be obtained is correct. That's the process that we are undertaking now.

MR. RODGER: Maybe if you could help me, Mrs. Formusa. Which sites have the exemption orders attached with them? Or if I could find that out; I don't have to know now.

MRS. FORMUSA: It would be in the Gazette, somewhere in there. But generally, our existing facilities, or fossil facilities, all predated the passage of the Act, and in some case, they were

grandfathered by way of an exemption order. And a lot of the rehabilitation work and maintenance work at those stations is covered by those exemption orders, but I believe it applies to all of our facilities.

MR. RODGER: Would it be possible to get that information, if it's not too much trouble? If it is too much trouble, it is not crucial, but I would be interested in finding that information if it was handy.

MRS. FORMUSA: I can provide that to you.

MR. RODGER: Okay. That is Undertaking 142.45. I believe.

Q. Now this may be a question for a later panel. But, Mr. Snelson, you also said that the acquisition time of 1 or 2 years presumes that the order books of manufacturers are not backed up as they may occur if all utilities run to buy a CTU at the same time.

I want to get an understanding of whether Hydro has conducted any surveys among various manufacturers on probable delivery times, on supply limitations, on world-wide demand, that kind of thing.

MR. SNELSON: A. My understanding is that the supply division made some inquiries on that about a year ago. I don't have the details of that.

Q. Would it be possible for you to go

back and make inquiries to see if such studies were done?

A. I think the question is probably better posed to Panel 8 who will have people who are familiar with the combustion turbine option on the panel.

Q. Okay.

Mr. Snelson, just staying with you for one moment. You also said in a response to one of Mr. Watson's questions that non-utility generators manage to buy combustion turbines and install them in less than that time, and that time was the 4-year lead time.

I wonder if you could tell me which of these non-utility generators you were referring to.

A. It was general comment. But ICG, that's -- I am not sure I can tell you what the initials stand for. It is the name of the company. I believe it's Fort Frances has installed about a 90 megawatt combustion turbine unit recently and there was not more than 2 to 3 years between the signing of that contract with us and their having that facility in service.

Mr. Vyrostko on Panel 5 would know more details about that.

Q. Do you know of any non-utility

generator that has put in a CTU the size of the CTUs which Hydro is proposing, 168 megawatts?

A. The reason that I mentioned the ICG one is that that is, I believe, the largest non-utility generator to -- the largest single CTU that has been installed, and that is a little smaller than the size we propose.

Q. So, to your knowledge, then, at least, no non-utility generator has put in a CTU the size of which Hydro is proposing, 168 megawatts, in the 3- to 4-year lead time?

A. Not to my knowledge. But if we ran into difficulty getting 168 megawatt CTUs and we needed the capacity in a hurry, we would find it acceptable to put in a larger number of slightly smaller units.

Q. Can I take it, generally, from your evidence over the past few days, that Hydro doesn't anticipate requiring a CTU within the next ten years, at least?

A. In the median load forecast, we don't anticipate CTUs being required in the next ten years.

Q. Okay. I will tell you my concern, my client's concern, is that as a result of various possible scenarios, Hydro might require a CTU or CTUs before that ten-year period. ...

[12:15 p.m.] Last week, Mr. Taborek stated that the reliability issues which we have been discussing in this panel, in a sense, are like a game of odds.

And if I can extend that analogy, AMPCO sees the CTUs as Hydro's ace up their sleeve, if you will, as a way of cutting down on those odds. And we are concerned that should circumstances come about where you may need a CTU, put in your order, and the manufacturers say, "Well, fine, Ontario Hydro, go to the back of the line behind everyone else," and that 3- to 4-year lead time will really be 6 or 7 years. So, that is our concern. And that's why I have asked you about which manufacturers, and has it been documented.

Given what I have told you, given that we in a planning process, do you feel it would be appropriate to have some kind of contractural arrangement with manufacturers so that the scenario that I have described won't come about?

A. The scenario you have described is a risk. It's one that is acknowledged in Hydro, within its planning.

If the probability of requiring CTUs was considered to be high enough, then a decision could be made to essentially buy options for combustion turbines as a protection against requiring CTUs and to buy a

place in the queue. As of today, that has not been considered a high enough probability to make that decision.

Q. But given the uncertainties involved in this whole process, it certainly wouldn't be unreasonable to approach manufacturers with that. As Mr. Taborek was indicating, there is is no way in this process we can define with certainty what is going to happen, so we want to hedge our bets as much as possible. So, in a planning environment, as we were in here, that might be a very good idea.

A. It's an idea that's worth consideration.

As I have said, the probability has not been judged high enough to do it as of this date.

Q. Okay. If the lead time for CTUs should turn out to be of 6 or 7 years, as opposed to 3 or 4 because of further environmental assessments or because of a backlog of orders, or whatever, how much would that delay add to the reserve level required to maintain the desired standards of unsupplied energy?

A. Well, we would have to consider whether the appropriate action was to raise the reserve margin, which might be considered appropriate if this was considered to be a phenomena that would exist for

an extended period of time, a decade or more.

The other option is to do something to address the long lead time of CTUs, and it is probably a better option to do something to address the long lead time that you have postulated for CTUs rather than to make an adjustment in the long-term reserve planning margin.

Q. Given the evidence before this Board, that is your target - 3, 4 years - and that's the kind of analysis that you are using and the analysis which the Board has to decide upon. If reality turns out to be 6 or 7 years, would you then go back and derive what the impact would be?

A. The lead time, you have postulated two conditions that could lead to that. One is long-order books of manufacturers, and if long-order books of manufacturers is a problem, the best solution, in my judgment, is to place options, the best long-term solution is to place options to reduce the lead time to more like the actual construction time, the actual manufacture time of the CTU, than to presume that that long lead time is going to persist forever and make an adjustment to the long-term planning margin.

Similarly, if approvals are a constraint, then that may be a situation that persists for a while,

but earlier in advance, approval processes can address the issue and reduce the lead time from the actual construction, the actual commitment to the in-service time to an appropriate level.

Q. So, I sense from that that there are things that can be done with respect to that lead time, you could place orders now or at least have some kind of contractual arrangements, you can get your specification work done now, you can prepare your environmental assessments now, ready to submit, should it be necessary?

A. Yes.

Q. And to date, Hydro has not looked seriously into those options I have just described? I know Mrs. Formusa talked about the site-specific issue.

A. A site-specific definition phase for combustion turbines was started in early 1990 and was stopped in mid-1990. The reason it was started was the reasons that we have just discussed. The reason that it was stopped was because the recession was apparent by late 1990 and the probability of actually meeting that advanced work was considered to be low enough and the expense not to be justified.

So, for the time being that work has not been underway, but it was considered last year and, in

fact, did start for a while.

Q. And for which Hydro site was that?

A. It was a process seeking to identify sites and a number of sites were considered.

Q. But no one site was specifically chosen?

A. I don't believe that a preferred site was identified.

Q. If there was a specific site identified, could you provide me with that information, please?

A. Yes.

Q. That's Undertaking 142.46.

---Off the record discussion.

MR. RODGER: Q. I wanted to clarify a couple of points with respect to emergency assistance. You went over in some detail that you have arrived at this 700 megawatt figure and that that's been the figure you used for some years now. But I didn't hear a response as to how that 700 megawatt figure was originally determined.

MR. SNELSON: A. The original documentation on that, I believe, was given in response to Interrogatory 2.7.1, which was the 1981 reliability criteria report, which I see from a note here has since

been given the number Exhibit 140.

Q. I don't recall seeing that. Could you give me a quick summary of how that number came about? I could have missed it.

A. Section 3 of that report, I believe, discusses it. That is pages 7, 8, 9, and 10.

Q. I will leave that now. I will review that over the lunch break and if I have any further questions, I will come back to it.

THE CHAIRMAN: I believe you said that that hasn't been changed since that was done. You haven't seen any need to change it because there hadn't been anything that you think is significant to cause that change to be made.

MR. SNELSON: That's correct.

MR. RODGER: Q. Perhaps while we have that exhibit out, if you could turn to table 5-2, I have one question regarding the Bruce heavy water plant.

THE CHAIRMAN: Sorry, Mr. Rodger, I missed that.

MR. RODGER: It's Figure 5-2.

THE CHAIRMAN: Of 87?

MR. RODGER: Sorry, of Exhibit 140.

Q. You will recall that this table shows

the system designed on 25 System-Minute Criterion, Occurrences of Load Cuts and Operating Actions, and one of the load cuts is the Bruce heavy water plant.

At the date on which this chart is based, which I believe is the early '80s, could you tell me what the load was at the Bruce heavy water plant?

MR. TABOREK: A. Approximately 150 megawatts.

Q. And what is the load at that plant today?

A. About 50 megawatts.

Q. And what is the load anticipated to be?

A. The same lower level, 50 megawatts.

Q. So since this chart was made, there is less power cut now--

A. Yes.

Q. --than there was when the chart was made?

A. Yes.

Q. I have a couple of questions on interconnection assistance. Just bear with me for a minute.

This is another clarification on page 74 of Exhibit 87. When you describe some of the major

factors affecting the amount of interconnection assistance, the fourth bullet is:

"Interconnection transfer capability, available for emergency assistance taking into account firm and economy transfers and wheeling of power."

Now, perhaps this is just the way I am reading this, but that suggests to me that emergency assistance is only available after the firm, economy and wheeling transfers; is that correct, or am I misreading this?

My point is, I would have thought that the emergency would have taken a priority.

MR. SNELSON: A. I believe that, in some cases, the emergency will take priority, and in some cases, it will not.

Q. In what cases?

A. For instance, if Utility A has arranged a firm purchase from Utility B - let's say both are in the United States - then that is a firm transaction which they are relying upon. And they have, perhaps, decided not to build their own generation because of that firm transaction. And to the extent that that uses transmission capability, then we couldn't call upon the emergency assistance that

prevented that firm transaction taking place.

Q. So, Hydro could conceivably have a situation where it has an emergency and it looks to others for help, and the scenario that you have just described exists, and, therefore, you wouldn't get that emergency support?

A. That is correct. And the same may be true of wheeling of power, if it's a firm wheeling arrangement.

With economy transaction, I am not sure how that would be managed in a specific case, but it may be that suitable arrangements can be made to have a system that has an emergency cause some economy transactions to no longer take place.

MR. BARRIE: A. In an emergency, we certainly would get priority.

Q. You would get priority?

A. Yes, on the economic, compared to economy.

Q. On the economy?

A. Yes. And that's laid out.

THE CHAIRMAN: Could you remind me what wheeling is? I can't remember. It has come up before.

MR. SNELSON: Wheeling is where one utility agrees to allow its transmission system to be

used to move power from one party to another party.

So, this a three-party transaction. You have one party who is selling generation, another party is buying, and there is a third utility whose transmission system is being used to allow that transaction to take place, whose transmission is carrying the power from the generating utility to the receiving utility.

THE CHAIRMAN: And that could occur in firm contracts and in economy contracts?

MR. SNELSON: Yes.

MR. BARRIE: Yes. It typically happens when we buy from Ohio, cheaper power in Ohio. It comes in through Michigan.

THE CHAIRMAN: When you do these short term, you have to resort to 700 megawatts on the interconnections, how do you describe that contract? Is that an economy contract or a firm contract, or both? Or partly one, partly the other, or something different?

MR. BARRIE: I think you have to distinguish this 700, which is a planning assumption, and the specifics of the contracts that I described. In actual fact, it could be anything. A figure of 700 is assumed for planning purposes.

THE CHAIRMAN: But if you are in the midst of doing today's operations and you, all of a sudden, need something from Michigan, now you get that instantaneoulsy, or if it's available, I take it.

MR. BARRIE: We would take up a short-term capacity requirement. That's our equivalent, if you will, in the operating time frame of a firm purchase. If it's needed for a day or a week or a month, then we arrange that, yes.

THE CHAIRMAN: But you have an agreement with Michigan to do that?

MR. BARRIE: To do that, ongoing.

THE CHAIRMAN: Ongoing. That's part of your firm contracts; is it?

MR. BARRIE: No.

THE CHAIRMAN: So there really are three kinds of contracts then, firm contracts, economy contracts and the kind we just described.

MR. BARRIE: That's right.

Firm, in our definition, is one over a long-term, a number of years. It would affect the amount of generation actually built, as distinct from how it's used.

MR. RODGER: Q. Staying with interconnection assistance for another moment. I

understand that a phenomenon called circulating power occurs between interconnecting power systems; is that correct?

MR. BARRIE: A. Yes.

Q. Could you describe what circulating power is, please?

A. When any utility agrees to purchase from another utility, a contract path is established. That is, if we agree to purchase from Michigan, we expect the power to flow on the Michigan tie lines between ourselves and Michigan. In actual fact, some of the power will circulate -- the power will go whichever is the easiest path. Most of it will come through the direct path that I described, but some will circulate through other utilities and will actually come into Ontario on the New York tie lines.

So, the power is, in fact, circulated from Michigan, through New York and into Ontario. That happens with every transaction that every utility makes. So, sometimes we are the cause of circulating power, sometimes we get the effect of circulating power.

Q. So is it possible, then, when a net transfer is made between the two systems, it can result in capacity limit problems?

A. Transmission capacity, do you mean?

Q. Yes.

A. Yes.

Q. Could you give me any indication of what the general level and direction of circulating power is with Hydro's interconnection with, on the first hand, New York, and with Michigan?

A. It's impossible for me to give you a number. It depends on the transactions going on at the time, not only between ourselves and the other utilities, but with all the utilities around us.

The most notable circulating power is the power that circulates around Lake Erie, which is roughly what I describe when I talk about Michigan and New York - the power is essentially circulating around Lake Erie. But I cannot quote you a specific number, because it's constantly variable.

Q. Is this problem one that Hydro looks at on regular basis?

A. Yes.

Q. It does analysis on how it changes from time to time?

A. Yes.

Q. And how, if at all, is the levels that currently exist, how is that anticipated a change,

say, in the next 10 or 15 years?

A. It is impossible for me to say how that will change over the next 10 to 15 years.

MR. SNELSON: A. There is some discussion of Lake Erie circulation attached to Interrogatory 2.14.95.

THE CHAIRMAN: 2.14.95?

MR. SNELSON: Yes. It has a figure of actual circulation for 1990, and I think it is February 1990 to January 1991.

...

[12:38 p.m.] MR. RODGER: Okay.

MR. BARRIE: I think the figure just demonstrates very clearly that even in any one year, the variation is tremendous on a monthly basis, and in fact can go in different directions depending on all the contracts that are taking place at any point in time.

MR. RODGER: Q. Perhaps I could ask you then, Mr. Barrie, does it now, or is it likely that the circulating power will cause or does cause difficulty when you have to make purchases for emergency assistance?

MR. BARRIE: A. We haven't had to make purchases for a true emergency for a long time. The nearest I suppose we came to it was when we were making heavy capacity purchases in 1989. At that time, the circulating flow problems did not prevent us making the types of capacity we wanted to make. We were able to make all we wanted, considerably in excess of 700, by the way.

Q. So, in the event that Hydro does have to make such emergency purchases, certainly the circulating power phenomenon would be somewhat of concern?

A. It could be a concern under certain

circumstances. It's just we have not experienced it being a limit at this point in time.

MR. SNELSON: A. It is one of the factors taken into account in judging 700 megawatts that is appropriate, given that the actual physical capability of the interconnections is much higher.

Q. Mr. Taborek, in your direct evidence, you stated that Hydro has changed its estimate on what relief it can expect to get from public appeals. You said back in the '80s you are estimating 10 per cent and now it is approximately 2 per cent. That's correct?

MR. TABOREK: A. Yes.

Q. And on page 80 of Exhibit 87 - I don't think you have to turn to it unless you disagree with me - but you have outlined one example that public appeals were issued in August of 1988 and December of 1989, and those public appeals achieved approximately 1 per cent reduction in demand. Is that correct?

A. Yes.

Q. I am wondering with respect to those public appeals in '88 and '89, was there a recent history of power cuts and/or public appeals in and around that time which resulted in only a 1 per cent reduction in demand?

A. Sorry, I am not clear. Do you mean were there public appeals prior to or after these events?

Q. Prior to. We say that if your estimate was 2 per cent and then when you actually did have a time when you made public appeals you got 1 per cent, and I am just wondering just before that was there a series of public appeals which would maybe deter people from reducing?

A. No, your assumption is a little different. Let me just consult for a moment and then I will answer your question.

Q. Sure.

A. No, there were none before that.

And just to clarify your point. At this time, our assumption was for 10 per cent. And it was the effects of these two public appeals, examining the effects of these two appeals just recently in doing this analysis that we changed to 2 per cent, so the 2 per cent assumption came after the public appeal.

Q. I see. So, on page 114, Table 6.10, of Exhibit 87, when you allow for 2 per cent of public appeals, based on your actual experience that has been 1 per cent. And I am wondering if we want to be on the safe side - and you have talked about that - I am

wondering whether the allowance should be more like 0.5 per cent or 0.75 per cent?

A. Yes, there is reason to argue that the public appeal at the time was actually less than the 2 per cent. We would view this as a conservative number.

Having said that, and I think we discussed some of this earlier, we did have a feeling that sharper and repeated appeals in more of a serious situation that we were in at the time would have more of an effect. So, on that basis, we felt this was the single best number to use.

MR. BARRIE: A. I did say, in answer to Mr. Watson's question on this, about how much a public appeal is worth, it is extremely difficult for us to tell how much we actually got because we are trying to forecast what would have happened had there not been a public appeal when we look back over an actual situation. So, it should be treated with some caution, the number anyway.

THE CHAIRMAN: Did you say the 2 per cent was a conservative number, having in mind that the experience was 1 per cent? Is that what you said?

MR. TABOREK: Yes. And actually what Mr. Barrie is referring to...

We made the appeal. We now have a record of the load. What we don't have is a record of what the load would have been like without the appeal.

So, what we do is we look for a comparable one. We make an estimate of what it was. And then, having got that information -- that was roughly 1 per cent, Dave?

MR. BARRIE: Yes.

MR. TABOREK: That was roughly 1 per cent, and then we felt that we could do better than that, perhaps, in a more serious circumstance.

THE CHAIRMAN: With a different type of approach?

MR. TABOREK: An intensification of the same approach, in effect.

MS. PATTERSON: But what Mr. Barrie is saying is that it could have been that demand would have gone up 5 per cent, and instead it went down 1, so it could really have been a 6 per cent response. You don't know.

MR. TABOREK: Well, given, as we say, that the reference we don't have. And so we believe there was this small response, we believe it was 1, and we have modelled it with 2.

MR. RODGER: Q. Perhaps I could ask you,

Panel. If you had to start all over today with this exhibit, what would the number be for public appeals, given what you've --

MR. TABOREK: A. The number that's there.

Q. The number that's there.

I would like to turn to cost of customer interruptions. This was discussed yesterday but I have a few additional points.

First of all, your customer groups, two of them were large users and small industries, and I understand that large users, entities that went in that category had demand over 5,000 kilowatts. Did that category stay the same throughout your analysis of customer costs? And I got that reference from page 5 of Exhibit 140.

A. I am not aware of any changes.

Q. If there is a change, could you let me know?

A. Yes.

Q. You discussed the Saskatchewan survey, and I understand that that survey considered neither large users nor the small industries?

A. Saskatchewan was farms and residential.

Q. Okay. So, it was restricted to residences and farms?

A. Yes.

MR. SNELSON: A. I think we have to be careful there. We used the data from that study for farms and residences. I am not sure as to whether, in fact, it had more information in it than that.

Q. Okay. Could you find that out?

A. Those were the two categories where we felt that our own customer surveys were not adequate.

Q. I was under an understanding that those were the only two entities that the survey looked at. If that's the case and it did expand to other entities, I would be interested in finding out what they were, please.

A. We can look into it.

Q. And that is Undertaking 1.42.47.

MS. PATTERSON: 142, not 1.42.

MR. RODGER: All right. I will get it right yet.

Q. For the farms and residences that were a part of that University of Saskatchewan survey, was that a survey of farms and residences across the country or just Saskatchewan or one or two provinces?

What was the specifics there?

MR. TABOREK: A. I don't know the answer to that.

Q. Could you find that out as well, please?

MR. SNELSON: A. Yes.

MR. TABOREK: A. Yes.

MRS. FORMUSA: Why don't we do it as part of the same one because we are going to look at the survey and we can get both.

THE CHAIRMAN: All right.

MR. RODGER: Okay.

Q. Well, I will wait until I get that information because I am concerned if the residences and farms are just located in Saskatchewan, say, and that is a very different type of electrical consumption than farms and residences in Ontario. And I am just concerned that it's comparing apples and oranges, and the numbers from the Saskatchewan survey may be inapplicable to Ontario. That's why I'm asking about that.

MR. SNELSON: A. My recollection is that the survey was conducted by the University of Saskatchewan, that it was done for the Canadian Electrical Association. As such, I would doubt that it

was confined to Saskatchewan.

Q. I'm sorry?

A. I would doubt that the sample was confined to Saskatchewan.

Q. Okay. Well, maybe I will wait and get that information. I may have further questions on that.

Just before we leave that survey though, I have one further point. In my package, I include Interrogatory 2.24.1. And it's actually Exhibit 140 that is attached, but I assembled a slightly different package for the panel and for the other intervenors, so, if we could work from my package.

And my question stems from the cost to large farms. If you turn to Figure 1 of Exhibit 140, do you have that, Mr. Chairman? It is actually attached to the --

THE CHAIRMAN: I was looking at your interrogatory. Figure 1?

MR. RODGER: Yes, it's in the interrogatory that I handed to you. It should be one of the pages.

THE CHAIRMAN: All right. Page A9 of Exhibit 140, would that be right?

MR. RODGER: I'm sorry, it is Figure 1.

It looks like this.

MRS. FORMUSA: Yes, it is page A9 from Exhibit 140.

MR. RODGER: I see, you are right. You are right, Mr. Chairman.

Q. And you will see with that, that the large farm cost in 1980 was $275.70. And we will also see that the large user figure was $3.97. Now, if we put those figures -- just keep them in our mind, for the moment.

On page 82 of Exhibit 87, we have Table 4.8. And for large users the 1990 figure is $6.32. So that's up from the $3.97 of the Figure 1, Exhibit 140.

Now, what I do is, I divided that 1990 figure by the 1980 figure, and I got a factor of roughly 1.6, and I multiplied 1.6 by the 1980 estimate for large farms and I got a number of, approximately, $480, I believe.

When you look at the Table 4.8 on page 82 of Exhibit 87, you see that the farm cost is now 74 cents; that's from my calculation of over $400. And you touched on this briefly, about its being the Saskatchewan survey, but I am just wondering, that tremendous difference in customer costs for farms, how did you arrive at that figure?

MR. SNELSON: A. Can I put the $275 in perspective that is in Figure 1, page A9 of Exhibit 140?

Q. Yes.

A. First of all, that was large farms and not all farms. So some of the large farms may have responded to our survey on the basis of very large costs from, for instance, broiler operations of raising chickens, where if the electricity is lost, then the herd of chickens dies for lack of water. (Laughter) Flock...

Q. I would have said gaggle, so I am no better. (Laughter)

A. And so it was perhaps a survey of only a small proportion of farms. At the time that we had that estimate, we used it with a great deal of caution. And it was the best data we had, but we did not generally consider it to be acceptable.

And if you turn to page 5 of Exhibit 140, in the middle of the third paragraph, and I will read a couple of sentences. It says:

> "It can be seen that the current estimated of losses from large farms is much higher than for other customer classes. The possibility that this

estimate is too high cannot be ignored. This number has a significant impact on the customer damage costs as discussed in Section 2.5. However, it is also possible that the residential costs may have been under-estimated since studies in other countries have indicated customer damage costs considerably higher than the Ontario Hydro estimates."

So, at the time, we considered the large farm and the residential customer costs to be generally unsatisfactory in that they seemed to be outside of the bounds that we expected, but offsetting.

In the analysis that is in that report - and I will refer you to Figure 2-6 which is the back of Exhibit 140, about five pages from the end - the customer damage costs in that figure are plotted two ways. One is labelled 1980 estimate and one is labelled SEPR, S-E-P-R, estimate.

The SEPR estimate excludes the large farms, and the 1980 estimate includes the large farms. And we treated both curves in making our judgment as to where we should set the reserve level, and so we were quite uncertain at the time as to what weight, if any, to give to the large farm estimate.

Q. I take it in that 1980 figure those large farms, that analysis was restricted to large farms in Ontario?

A. The survey was of large farms in Ontario, yes.

MR. RODGER: I think that's as far as I can go on this question without having any information on the Saskatchewan survey, so I will leave that for now.

Mr. Chairman, I am starting a new set of questions. Would you like to take the lunch break now?

THE CHAIRMAN: Are you now on the two-third point, or ahead, or behind that?

MR. RODGER: I am about the two-thirds point, believe it or not.

THE CHAIRMAN: All right. Two-thirty.

THE REGISTRAR: We will adjourn until two-thirty.

---Recess at 1:00 p.m.

...

---On resuming at 2:35 p.m.

THE REGISTRAR: This hearing is again in session. Please be seated.

THE CHAIRMAN: We are now going to deal with some transcript alterations, using a neutral word.

MRS. FORMUSA: That's correct. I met with Mr. Watson, and with the exception of one of them, we are in agreement, subject to your comments, that the transcript should be changed.

The change in the words, I think you will see, makes the sentence make sense, or more sense than what it was. But if I can go through them...

THE CHAIRMAN: Let's just talk about the mechanics. This is the first time we have done this, I think, isn't it?

Should the changes then be documented and put on the record in some fashion,or is it good enough just to attach them to the next transcript that comes up out?

How is it dealt with in your programming?

MR. NUNN: As long as it comes out in the transcript.

THE CHAIRMAN: The transcripts are already in the system, aren't they?

MR. NUNN: Sure, but we can catch it,

looking at today's.

THE CHAIRMAN: All right. So, that's not a problem?

MR. NUNN: It's not a problem.

MRS. FORMUSA: As long as I read it in. What I have also done is prepared a typed list showing the volume, page and line number and correction from and to, so we will have that as well.

We begin with Volume 16, page 2857, line 8.

THE CHAIRMAN: Just a minute now. Line 8, yes.

MRS. FORMUSA: The word "programs" should read "stations."

THE CHAIRMAN: "A small hydraulic station"?

MRS. FORMUSA: "Of the small stations."

THE CHAIRMAN: "Of the small stations."

MRS. FORMUSA: So the sentence would now read: "A small hydraulic program, where we assess the requirements of the small stations and retrofit as required."

At page 2858, which is the next page, at at line 11, the word "replacement" should read "refurbishment." Here, again, we are talking about the

hydraulic units.

Page 2860, lines 1 and 3. Change line 1 first. "Hydraulic" in the first sentence should be "fossil," and "fossil" in the third sentence should be "hydraulic." So, the sentence now reads:

"The fossil and the nuclear units, you will see, are pretty well off the page compared to hydraulic."

Volume 17, page 2950, line 2, where you see the word "add" --

THE CHAIRMAN: I haven't quite got it yet.

MRS. FORMUSA: Sorry.

THE CHAIRMAN: Line... ?

MRS. FORMUSA: Line 2, the word "add," should instead read "multiply by." This is where we were talking taking the unsupplied system minutes and multiplying the customer damage cost in order to define the customer interruption costs.

Page 2957, line 22, the multiplier was left out here. Line 22, at the end of it, after F&D run should be inserted "by customer damage cost." So if one reads the sentence now, it is: "Multiplying the unsupplied energy from an F&D run by a customer damage cost, which gives you the worth to the customer."

2978, line 19, "18 months" should be "12 months."

THE CHAIRMAN: Just a moment. "18 months" should be "12 months." All right.

MRS. FORMUSA: Page 3009.

MR. WATSON: Mr. Chairman, up to now, I have had no difficulty with any of these corrections, and, in fact, I agree with all of them. The one on 3009, I simply haven't had time to think about where, in fact, that fits into our categories, whether that's simply the same type of correction, or whether it's something that requires a little further thought.

THE CHAIRMAN: Let's get what the suggestion is first. Can we do that?

MR. WATSON: I have no difficulty with that. I just want to be on the record as I will need some time to think about this one.

THE CHAIRMAN: Okay.

MRS. FORMUSA: 3009, lines 20 and 21, I understand that the answer given: "No, I couldn't imagine," should be replaced by the following, and I will just read it out.

THE CHAIRMAN: Is it lengthy?

MRS. FORMUSA: No, it's one sentence.

THE CHAIRMAN: All right.

MRS. FORMUSA: It should be: "There would be a difference if the units removed had different forced outage rates."

THE CHAIRMAN: "There would be a difference..."? What happens after that?

MRS. FORMUSA: "There would be a difference if the units removed had different forced outage rates."

THE CHAIRMAN: And that replaces the sentence: "No, I couldn't imagine"?

MR. TABOREK: Does the remainder of the sentence remain?

THE CHAIRMAN: Do the words, "Especially if you are just deleting them," stay in?

MR. TABOREK: No, that would come out, too.

MRS. FORMUSA: Sorry, both sentences come out.

THE CHAIRMAN: Now, this seems to be a change, at first blush, at least, and whether it's a significant one or whether it's one that should be allowed to be made, or whether it's one that may need further cross-examination is something that Mr. Watson wants to consider. And I think he is entitled to do that.

So we will just leave that one in abeyance for now.

MR. WATSON: Thank you, Mr. Chairman.

MRS. FORMUSA: I will delete it from the list, then, that I handed in.

THE CHAIRMAN: Yes, I think that is probably the best way. I will count on you or someone else to raise it again if, as and when it's going to be done, otherwise there will be no change made. So we will leave it that way.

MRS. FORMUSA: I understand.

Finally, on page 3017, line 8, where you see the words "very quickly," we wanted to change "very quickly" to "in about eight hours."

THE CHAIRMAN: Take out "very quickly" and say "in about eight hours"?

MRS. FORMUSA: "In about eight hours."

Here we were talking the shutdown of the vacuum buildings and the time that it would take.

Subject to the one on page 3009, I will submit a list that shows all of those changes that I have read into the record.

THE CHAIRMAN: Thank you.

I don't want to encourage this, so I would just say to everybody, be very careful what you

say; I'll put it that way.

Mr. Rodger?

MR. RODGER: Thank you, Mr. Chairman.

Q. Panel, before the lunch break we were discussing customer cost of interruptions, if I could turn to that subject again for a few minutes. I believe we were looking at page 82, of Exhibit 87, table 4.8, which is the cost of one one-hour interruptions. And we see on that table that the 1990 weighted cost average is $5.91. And there is evidence in the past couple of days that the way that Hydro got that number, $5.91, was by using an escalator applied to the earlier numbers of the surveys done in the '70s and the Saskatchewan survey in the '80s; is that correct?

MR. TABOREK: A. Yes.

Q. Could you expand upon that escalator, as to just how this figure was arrived at? What were the factors that went into that escalated number?

A. I would presume it's the price index.

Q. Yes?

A. But that's all I can give you.

Q. If there are any more factors, could you let me know, please?

A. Yes.

Q. And that, I believe, is Exhibit 142.48.

I will tell you my client's concern with that escalated figure. I will give you a real life example. One of AMPCO's members is Ford Motor Company of Canada. And like many industries in the '80s, and after these surveys were done by Hydro, Ford installed a lot of robotic type equipment for their assembly line, a lot of computerized machines, and so forth. And I put it to you that that is one example, but that was pervasive throughout industry in the '80s.

And when Ford gets hit with a power cut, or for that matter, when voltage is reduced to a certain extent, it causes these machines to shut down. And when they shut down, the assembly line shuts down. And as I am sure you are aware, when power is resumed, it's not just a matter of turning on a couple of switches and everything is back in full production again, but each of these robotic machines and other very highly sophisticated equipment has to be all reset, readjusted. And there are some extremely significant costs, and I put to you, you can use that example in a number of different industries.

I would like to find out how drastic changes in technology like that, in the '80s, were

incorporated into your analysis and incorporated into that figure of $5.91?

A. Those changes were not incorporated in this analysis. This was a straight escalation of the previous survey information as I have reported to you.

The other fact, though, is that we do report, for instance, that the sensitivity of the outcome, the reserve margin we are planning to, is not highly sensitive to the customer damage cost. There is a good deal of testimony to it, but it's basically a result of the minimum total customer cost occurring at very low values of system minutes, which is, in effect, reflecting the cost of kinds of sensitivity that the survey is catching. The kinds of sensitive sensitivities your client is expressing.

Therefore, as we noted earlier, that since a doubling of this number would - and again quoting from memory - I think, would result in a one per cent change in the reserve margin required, indicates that this is not a sensitive number. It doesn't have a big effect on the reserve margin used in the Demand/Supply Plan.

And furthermore, we were aware of the points you were making, and we view that as another

factor that -- we have described, for instance, that this analysis, by virtue of the several facts, would tend to underestimate what the true customer damage cost is, and it is one of of the factors that inclines us to move to the more reliable side, if you will, of the minimum determined by the straight analytical approach.

So it's not that that factor is not thoroughly understood or considered; it is just that the information is not here now to go further with it and it doesn't have a big effect.

Q. And that last statement would pick up on your earlier comment, Mr. Taborek, when you said that analysis will always - and I stress "always" - underestimate what a true minimum total customer cost would be?

A. Yes.

Q. This is an example of that?

A. Yes.

Q. What if I were to give you a hypothetical situation that, for industry, the real cost of interruptions is 5, 7, many, many times more than what you have shown here? How would that vast difference in the figures you are using and the numbers in the hypothetical, how would that change the

analysis, with respect to total customer cost?

A. Well, it would move to higher reserve margins, all other things being equal.

Q. Thank you.

---Off the record discussion.

MR. RODGER: Q. Would you agree that the cost to a customer of one one-hour interruption, they rise with the frequency of those interruptions?

And to give you an example, if an industry has one one-hour interruption per month, that's going to be a lot less costly than if you have, let's say, a series of 15-minute interruptions every second day in that month.

MR. TABOREK: A. Well, generally, even a 15-minute interrupttion, for instance, would -- if we were to do this calculation on the basis of 15-minute interruptions rather than one-hour interruptions, it would double the -- roughly, make the $5.91 number in the range of $10 an hour.

Q. So there is, then, if you can call it, an escalating unit cost when it comes to the frequency of interruptions? Would that be a reasonable description?

A. I am prepared to testify to that. I am not prepared to go further. I can't testify further

on that.

Q. Maybe could you tell me, I am unsure how that escalating unit cost with respect to frequency of interruptions, how is that taken into account in that $5.91 figure?

A. It is not taken into account.

MR. SNELSON: A. The frequency effect that Mr. Taborek has just mentioned doesn't relate to having more one-hour interruptions; it relates to replacing a given number of one-hour interruptions by four times as many 15-minute interruptions, which is exactly the same amount of interrupted energy.

Q. Right.

A. If you were to be in the situation where you had increasing frequencies of interruptions up to many, many times what is currently projected, then the effect you describe may take place of increasing damage costs. But there is also the responses of customers who experience unreliable supply and take measures to protect themselves against frequent interruptions.

...

[2:53 p.m.] If you have an interruption one day in ten years, you may not decide to buy your own emergency back-up power supply. If you have an interruption one day a week, you may decide to do that and thereby cut your customers' cost of interruptions. But that's not something we recommend. It is just one of the effects that can take place.

Q. Just so I am clear. The multiple one-hour interruptions that we spoke of, that analysis, though, is not included in this $5.91 figure?

A. This is estimated from customer survey data asking about the effect of such an interruption. I am not sure that the data speculated about whether it would be different if the interruptions were frequent or infrequent.

Q. So, the answer is no? Or you are not sure?

A. As far as I know, this is based on a single one-hour interruption.

Q. If the answer is different, could you advise me, please?

A. Yes.

Q. 142.49, I believe.

I wonder if you can turn again, please, to Interrogatory 2.24.1? And for the panel, it's

figure 2-5, which is the third page of the handout, and it's the chart entitled "Target Generation Reserve on the East System."

And you will note --

MR. TABOREK: A. Excuse me, Mr. Rodger, what figure number is it in Exhibit 140?

Q. It's 2-5.

And you will see in the middle of that page, there is one reference to costs of indirect losses due to generation unreliability. So, if we keep that phrase "indirect losses" in mind, I would now ask you to turn to page 83 of Exhibit 87. And the first line at the top of page 83, "The costs listed above are direct costs only. The indirect costs may be equally important."

First of all, does indirect costs, as shown on page 83, does that mean the same thing as indirect losses, as shown on Figure 2.5?

A. We believe it to be the case. However, I have attempted to find the background material to these indirect costs and I have not been able to do so. This is the 1980 analysis, so while I believe so, I can't be certain.

Q. If we can assume for the moment that they are the same thing, and indirect costs, as I

understand Exhibit 87, could include things like loss of business confidence, its effect on expansion decisions and plant location, how do you go about estimating or attempting to estimate that cost?

A. In this instance, in the 1980 work, I believe we asked our economics and forecast division to make an estimate of that nature -- or the then economics division. We did not attempt to do that this time.

Q. Which panel might be able to address that, if any?

MR. SNELSON: A. I am just looking for some material. I believe that in the fifth interim report of the system expansion program re-assessment study, that the indirect costs are addressed in that report and the method used to determine them.

I am speaking here from memory, but I have looked at it fairly recently and if my memory is correct, that's where it is addressed, and that was given in response to an interrogatory. I am trying to get the number of it. It is at 2.7.80.

Q. 2.7.80.

A. Yes, I believe it is in the fifth interim report.

Q. So, in other words, Hydro has

attempted to quantify that effect of --

MR. TABOREK: A. This is in reference to the 1980 analysis, not recently.

Q. Okay. But given the age of the analysis, Hydro still made an attempt to quantify the effect of poor reliability on business investment plans in the province?

MR. SNELSON: A. It was an attempt to quantify the secondary effects, and that would have been part of the secondary effects, the effects that were considered. Whether they would have been explicitly identified, I rather doubt that.

Q. Do you recall the conclusions of that analysis?

A. The conclusion is the figure that you have in Exhibit 140 which shows the indirect effects added on top of the direct effects.

Q. Okay.

Now this morning we talked about various phenomena with respect to the transmission system, and I would like to raise one more. And that's the 500 kilovolt flash-over problem. I wonder first of all if you can describe this phenomenon, please?

MR. BARRIE: A. Yes. In 1986, in March of 1968, we experienced in a number of simultaneous

flash-overs on the 500 kV. What that is is where there is, on the insulation between the conductors and the ground, a breakdown in the insulation, and the electricity can flash over between the conductor and the ground. This can happen at any time. But it would not normally happen, especially simultaneously.

So, we experienced this, as I say, in March 1986 on many, many 500 kV insulators. It caused almost the -- we lost virtually all circuits in the Bruce to Milton area at 500 kV. It was an extremely serious problem for us.

Q. And I understand, Mr. Barrie, that this problem has been under investigation by Hydro's research division for a period of years now?

A. Yes. Ever since 1986.

Q. If I could refer you to AMPCO Interrogatory 2.24.12, please?

THE CHAIRMAN: 12?

MR. RODGER: Yes, 12.

Q. And in this interrogatory, we asked you about this problem and about the research that Hydro has done and is doing. And as part of the response, Hydro stated that the information requested was not used in the development of DSP for reasons outlined in response to Interrogatory 2.7.11. And

basically, if you paraphrase the answer, it was that the details of transmission limits did not impact on the generation reserve requirements.

And I am not sure I understand that response, because since transmission unreliability is a rather significant source of interruptions and overall system performance, we would like to assess whether the flash-over problem is likely to persist in the future, as a future source of interruptions.

So, I guess, my question is, could you describe, first of all, describe the status of the research and whether you have any remedies for this problem, either now or in the foreseeable future?

MR. BARRIE: A. As we have said, our research division have been working on this problem for a number of years now. It is a complex problem. It involves special weather conditions, it occurs when very specific weather conditions occur, that is, temperatures just below freezing, a slight warming trend, freezing rain, that kind of condition.

The work at research is likely to continue for at least another year before they will be making firm recommendations as to the long-term solution. But I should say that in the operating time frame, we are taking measures to ensure that when this

situation does occur, the customer, to the maximum extent possible, will be unaffected. We adopt what's called a "safe posture" on the bulk electricity system when this kind of weather is either forecast or, in fact, takes place.

What that means is that we generally adopt a more conservative approach to the way we operate the system. That involves usually running less economic plant to reduce flows on transmission lines and to generally position the 500 and 230 kV systems such that, if this does occur, we will be in a better position to withstand such events.

Q. Since 1986, when Hydro's research group started its review and study of this problem, have they issued any reports on this matter?

A. Not that I am aware.

Q. So it is an ongoing --

A. Yes. The latest report I had was that there would be a report on what is being proposed later this year, but that remedial actions wouldn't take place until sometime after that.

Q. Do you know if Hydro is planning to release that report when it is finished?

A. I don't know for certain, but I imagine there will be tremendous international interest

in it. It is a situation that can be faced by anyone who experiences the kind of weather I have just described and has 500 kV equipment. So, I imagine it will be made public and we will probably publish it in a technical journal, but that is all supposition on my part.

Q. So, it would also be supposition to suggest that that report might become an exhibit at this hearing?

A. Yes.

DR. CONNELL: Mr. Barrie, may I just understand. This is an event that could happen on any line at any transmission tower, could it?

MR. BARRIE: The phenomena seems to only affect the 500 kV.

DR. CONNELL: Yes.

MR. BARRIE: It doesn't seem to affect the 230 and 115 kV, but it could happen at any 500 kV station anywhere in the province.

DR. CONNELL: So there is a momentary arcing across the insulator to the tower?

MR. BARRIE: Yes, that's right. This causes the line to trip.

DR. CONNELL: I see. So, it is out of action then?

MR. BARRIE: Yes. The lines are protected against such events occurring, and so the circuit-breakers at either end of the line would trip out the affected portion.

DR. CONNELL: When would you normally connect the circuit again?

MR. BARRIE: We would normally try it straight back when something like this happens, because it tends to be a transitory thing, and we are okay.

But on this particular occasion, with this kind of weather, we experience multiple trips. We put it back and it tripped back out again. There were actually 57 flash-overs in this particular occasion.

DR. CONNELL: How many?

MR. BARRIE: About 57 flash-overs. This was in March of 1986.

DR. CONNELL: And how many circuits would that be on?

MR. BARRIE: It was on nearly all of the 500 kV circuits from Bruce and Nanticoke through to Cherrywood, so we have named three of the major 500 kV stations on that system. And all circuits at all three stations were affected. I am not sure exactly how many circuits that has, but it would probably be in the order of a dozen.

MR. RODGER: Q. Let me see if I can tie this together. I had put to you a number of different phenomena that affects the transmission system. And in Exhibit 87, you discuss transmission reliability and you confirm that reliability of supply to customers is affected not only by generation, but that the transmission system is also a very important part; and that, in fact, transmission constraints and failures contribute significantly to overall system reliability; and that, by neglecting the transmission constraints and setting the reserve margin target, that is an "important real life limitation," and that's quote.

Is there a way --

MR. TABOREK: A. A quote from where?

Q. That is page 21 of Exhibit A-7.

The exact quote on page 21 is:

"For example, neglecting the transmission constraints and setting reserve targets is an important real life limitation."

And my question is, given the problems with the transmission system, serious problems and the series impacts they could have -- because, to a customer, the result is the same whether it's a generation problem or a transmission problem - they

don't get the supply, so the end result is the same.

Given the importance of the transmission constraints, isn't there some way that Hydro could and should incorporate this problem into either the F&D model or some other analysis that it has brought into the reserve margin analysis?

A. Definitely not into the F&D model. But as an important factor, it should receive due consideration in the corporation's plannings for its capital expenditures.

I have alluded to the -- I have said directly that the analysis of reliability is very difficult because of the complex nature of the electricity system and the rarity of the events that occur and the difficulty of getting good data to model those events.

There is a body of research that is on the leading edge, if you will, of reliability planning that is attempting to combine generation and transmission into one overall analysis. Simply stated, that has a long way to go and it is by no means clear that it will ever be successful, by virtue of being so complex and the difficulty of getting data.

Having said that, there are other ways to assess the balances that are made on expenditures

between generation and transmission. First of all, we would argue that it is entirely appropriate to view generation reliability on its own, in this circumstance, the way we are doing it.

The example you chose illustrates the reason why we say this; namely, that the solution to a transmission problem is to fix the transmission problem or to change your method of operating rather than to have reserve margin. Generally, and I think somewhere in here is a statement to the effect that it's generally cheaper to fix the transmission than to add reserve margin.

...

[3:15 p.m.] Having said that, there is another question about how do we know that the corporate expenditures are appropriately balanced.

Here again, there is not a body of analysis, if you will, that will indicate that this is an optimum generation versus transmission expenditure pattern. But there are, in effect, two avenues that address this.

One is that utility management, basically, senior management spends a good deal of its time attempting to make that judgment. They are, in effect, optimizing with their judgment, using all of the inputs about different problems that they have.

And utilities across North America are doing it, and so there is -- in effect, the judgments utilities are making are focused on that capital spending balance and associated maintenance.

There is another factor that some transmission spending can be considered in an optimum. Some must be done by virtue of the requirements that are put on you. Some can be related to reliability and traded off against generation.

What you can do in the short term, in the absence of these global models that optimize everything that everybody can think of, is to compare the

generation and transmission expenditures and the gains in unreliability savings that are made, against the customer damage cost.

So, for instance, our proposition here, is that generation expenditures are appropriate if they give a return of more than $5.91 per hour, in effect, of customer damage cost.

You can apply that same criteria to the transmission where it is reliability-related, and you can get some insights as to the balance that you are, in effect, balancing your generation and transmission expenditures. Now, that's a kind of a shortcut judgment exercise through to which these grand models, if they ever come into being, would ultimately lead you. But we have said there are limits to how far generation models can take you. There will be even more limits to how far generation and transmission models take you.

So, in conclusion, it is entirely appropriate to plan generation, using generation only, and excluding transmission.

Q. Given what you have said, and understanding that it is very difficult to try and make predictions about transmission reliability, would it not still be fair to suggest that for planning

purposes, for the planning purposes that we are involved with in determining that unsupplied system minutes, the analysis as it stands now is deficient because it does not incorporate those transmission limitations?

A. No, it is not deficient. It is entirely appropriate and to the point.

And the reason is that if there is a transmission problem that is affecting reliability, the preferred course of action is to fix that problem and that is cheaper than adding generation reserve to fix it.

Q. So, in other words, when the problem occurs, then we will deal with it?

A. No, that's not the statement.

Q. I don't mean to be curt, but maybe I just misinterpreted that.

I am suggesting a scenario where, although we realize it's uncertain - the transmission constraints are uncertain - it's one of a multiplicity of uncertainties in this entire process. And isn't there a way that we can somehow factor that in to be a reserve margin, or factor it in elsewhere, where we can anticipate problems and have some kind of a basis from which we can deal with the problem before the problem

occurs?

And I am getting the sense --

A. You are seeking, if we could predict a transmission problem, such as the flash-over problem or some other future thing like it would occur in the future, we would design it out now and it wouldn't occur.

Q. Well, maybe I could ask Mr. Barrie. Yesterday you stated that there was two new programs which Hydro was going to introduce on remedying the various transmission problems that we talked about, at a cost allocation of approximately $100-million. Is that a fair recollection of your evidence?

MR. BARRIE: A. The costs I quoted were -- I think the words I used were, in excess of 100-million, and it is per year, from 1993 onwards. So it is a significant -- well, it's two programs actually.

Q. What are those two programs?

A. One is transmission station rehabilitation, which is things like looking at circuit-breakers at the station, some of which are very old - both oil and air blast circuit breakers that need remedial work; transformers, some of the gaskets on the joints are leaking, we have to fix those kinds of

things. It's a number of activities, all to do with rehabilitating equipment at stations.

Q. Is there a priority in these programs, that certain things have to be dealt with before others, with respect to the transmission system?

A. Could you just wait one moment?

Q. Sure.

A. The critical items that are listed were what I just said, transformers, circuit breakers, and some of the high pressure air systems which are again associated with circuit-breakers. I don't have details on a station-by-station basis, but those are the items.

Q. All right.

A. That's one program.

The second program is to do with the transmission line refurbishments, which involves inspecting and then doing whatever work is needed to refurbish the transmission lines - this is the major lines, especially the older ones - to restore them to the condition that they need to be in.

This is actually the bigger of the two programs.

We have 27,000 kilometres of overhead line and about a third of these lines are 40 years or

older as of 1990.

Q. One-third?

A. Yes. So, the plan is to refurbish about 400 kilometres of line per year over a 10-year period. So that amounts to $80-million per year.

It should be clear, this will not solve some of the other problems we talked about earlier. The need for special protection schemes, the short-circuit level problem, the flash-over problem, those are all individual items that that will be addressed. These are general improvements, rehabilitation of old equipment.

Q. Thank you, Mr. Barrie.

I have, of course, a couple of questions with respect to Darlington. The existing system assumes that Darlington will be in service by 1993. Can you tell me what the current status is of Darlington, with respect to equipment problems?

I understand that there were some fuel problems, fuel bundles cracking is what I have been advised, and also some generator shaft problems that have cropped up.

A. I could give you a brief overview, but Panel 9 would be in a far better position to describe the detail.

Q. An overview would be helpful now.

A. Both Units 1 and 2 are off-line at the moment.

Unit 2, problems associated with the fueling machine and the broken fuel bundles. The exact cause is yet to be established, but it is to do with the fueling machine and the fuel bundles.

Unit 1 has been taken off to inspect the equipment, to see if the same problem existed with No. 1. We have not discovered broken fuel bundles, but there is some evidence there may be a problem with No. 1 as well. However, that's very recent information and I don't have the detail on it.

We currently don't expect Unit 1 or 2 until November. Unit 1 will be on for some time during the summer for tests, but we will not have them in service fully until about November of this year. That's our present forecast.

Q. Sorry, that was Units 1 and 2?

A. Yes.

Q. Can you tell me how much the current projected in-service dates for all units, how does that compare with the 1986 estimates?

A. I don't have that information.

Q. I just want to get a general sense of

how much the dates have slipped since '86.

Well, if we don't have it here, perhaps I could get that by way of undertaking?

THE CHAIRMAN: I think we may have it.

MR. TABOREK: I think we will take an undertaking.

MR. RODGER: Q.. 142.50.

You spoke, Panel, during the past couple of days, about rotating load cuts. Does Hydro have the ability to categorize the loads which are the subject of rotating load cuts? And I mean by that, some loads are more critical than others and Hydro might decide that loads to hospitals will take the first priority, as an example, and that other loads are less critical. Are you able to do that for rotating load cuts?

MR. BARRIE: A. We have some ability to do that. It depends on the extent of the required load cut.

With a very large load cut, we have less discrimination. If the load cut is less severe, more localized, then we have a bit more discrimination to cater to high priority loads.

Q. Does that ability vary depending on where where you are in the province, or is it more of a general?

A. To some extent it does, yes.

Q. Could you give me a --

A. If we are shedding load at the bulk supply points, it tends to be we have less discrimination. That is, if we shut down a whole bulk, big bulk supply point, or feeders from a bulk supply point, then you will lose all the load associated with the feeder from that bulk supply point. That would be the normal kind of rotating load cut we have been referring to here, if we were in a generation shortfall.

However, there are some examples quoted in response to one of Mr. Watson's questions, where we indicated that when we did learn about special places, there was a quote of a hospital, I believe, in North Bay, where we did learn about that and we were able to exempt that particular place. That was actually a voltage reduction, that one, but the same could apply to an interruption as well.

Q. So, it can be done to a certain extent?

A. To some extent.

Q. Can you give me a very rough estimate, when you are talking about rotating load cuts, is it 5 per cent that you can have this capacity

or 50 per cent?

A. I don't know.

Q. Would that be difficult to find out?

A. Well, I will make an undertaking, and if it's difficult, I will have to tell you.

Q. That's 142.51.

MR. RODGER: Mr. Chairman, subject to the undertakings and any further questions out of those untertakings, those are all my questions.

THE CHAIRMAN: Thank you, Mr. Rodger.

MR. RODGERS: Thank you, Panel.

THE CHAIRMAN: Mr. Chapman, you will be ready to proceed after the break.

MR. CHAPMAN: Yes, I will.

THE CHAIRMAN: We will take the break now then and we will start in 15 minutes.

THE REGISTRAR: This hearing will recess for 15 minutes.

---Recess at 3:30 p.m.

...

---On resuming at 3:48 p.m.

THE REGISTRAR: Please come to order. This hearing is again in session. Please be seated.

MR. CHAPMAN: Good afternoon.

THE CHAIRMAN: Are you ready to proceed now, Mr. Chapman?

MR. CHAPMAN: Yes, I am, Mr. Chairman.

And assisting me is Elizabeth Brubaker at the table and Sheila Malcolmson is sitting to my left.

CROSS-EXAMINATION BY MR. CHAPMAN:

Q. The first area I would like to get into is with respect to current water rents for hydraulic stations, and I am advised that Mr. Snelson is the gentleman who probably knows most about that.

And in that regard, I would ask you to refer to the first item in our list of documents which consists of - its identification number is 2.2.2 - and it consists of an interrogatory that Energy Probe sent and it was followed by the master agreement which is dated July 4, 1985.

And the answer indicates that it outlines the most recent condition of water rental fees, which are paid on 48 hydraulic generating stations. Do you have that document?

MR. SNELSON: A. Yes, I do.

Q. And I see that at the end of that document, there is a letter from Edita Boni and it's addressed to Mr. John Botterill, the revenue co-ordinator for the Ministry of Natural Resources.

And on the second page of that letter --

THE CHAIRMAN: Excuse me, Mr. Chapman. Just a moment. It is a letter of January 22, 1991?

MR. CHAPMAN: That is correct.

THE CHAIRMAN: Yes.

MR. CHAPMAN: And the second page of that letter, Mr. Snelson, the fourth paragraph down, it indicates, "Then once again..." - I am quoting:

"Then once again, according to the working arrangement thus calculated, rate was divided by half and the half applied to a million horsepower generation guaranteed off Beck 2 generation."

Q. Now, the first question I have is why was it halved?

MR. SNELSON: A. The answer is I don't know.

Q. And my first thought was that it may have been that half went to the Ministry of Natural Resources and half to the Niagara Parks Commission, but you are saying you don't know if that's the case?

A. I don't know. You qualified your remarks by saying that you thought I was best able to handle water rental issues in this panel.

I don't think there is anybody on this panel who can speak definitively about water rentals. Water rentals, as you will note this is part of a Panel 6 interrogatory--

Q. Yes, I realize hydraulics are part of Panel 6.

A. --and the people with most knowledge of hydraulic will be on Panel 6.

Q. All right. The reason that I mentioned you as the person was because of a brief conversation I just had with Mrs. Formusa. And in fairness to her, she indicated that, of course, you would only be able to answer the questions that you had knowledge about, and I understand that.

But your answer is you don't know that, but that that could be answered by the hydraulic panel; is that correct?

A. Yes.

Q. Dealing with Beck 2, are you aware of the net energy that Beck 2 has generated, roughly, in the past five years?

A. We have it in answer to our

interrogatories, and it is not a difficult number to find. I can't quote you a figure off the top of my head.

Chapter 4 of the Demand/Supply Plan, Figure 4-20, which appears on page 4-16, and I believe this is Exhibit 3, shows a typical energy output for the Sir Adam Beck No. 1 generating station of 2,085 gigawatthours per year. And for Sir Adam Beck No. 2 generating station of 9,941 gigawatthours per year.

Those are typical figures. I am not aware of how the last few years have deviated from that, but the deviations would not be very large.

Q. And you have indicated you are not the person to ask about the rents; is that correct?

A. Yes.

Q. Let me try this. I see that the rents refer to horsepower. Are you able to translate horsepower into gigawatts?

A. That's what appears to be on this document, yes. Water rents, I believe, are specified--

Q. In horsepower?

A. --in some cases in horsepower.

Q. Would you know the relationship between horsepower and gigawatts?

A. There's 746 watts --

Q. 746?

A. 746 watts per horsepower.

Q. All right.

A. So 1 horsepower is 0.746 kilowatts.

Q. Thank you.

It is your understanding, I take it, that Panel 6 will be the panel that will be able to discuss these rents on the existing system?

A. Panel 6 will be able to discuss details of the existing and future hydroelectric generating units. I presume that they can deal with more detail on the water rentals than I can, for sure.

Q. Now dealing with this agreement again. I see that there is a Schedule A attached to it.

THE CHAIRMAN: This agreement being the agreement with the --

MR. CHAPMAN: Yes, the water rental agreement that is attached to 2.2.2. It is called the "Master Agreement."

THE CHAIRMAN: Dated the 4th of July, 1985?

MR. CHAPMAN: Yes.

THE CHAIRMAN: And you are referring to Schedule A; is that right?

MR. CHAPMAN: That's correct.

Q. Now on the schedule, I am referring to the three hydraulic stations on the Ottawa River. And the first one that I am referring to is Chenaux, C-h-e-n-a-u-x, and they are all alphabetical. It is the 12th one down. And going over to the right, it says installed capacity, it reads, 122,400 and has deemed capacity of 61,200.

The next one on the Ottawa River is Des Joachims, D-e-s- J-o-a-c-h-i-m-s; again, the installed is 360,000; the deemed is 180,000.

The next one on the Ottawa that I am referring to was called, Otto Holden, O-t-t-o H-o-l-d-e-n. The installed is 205,200; the deemed is again half, 102,600.

My question is, do you know why it is halved?

MR. SNELSON: A. No.

Q. All right.

Are you able to indicate why the deemed capacity is nil for 15 stations on that?

A. No.

Q. Now in the demand/supply environmental analysis at page 6-5, Hydro has said that - it is just a short quote I am going to read to

you:

"Recent regulatory initiatives suggest that large water users, like Ontario Hydro, could have to pay more for the water they use."

Now, I understand that that was based on, and I am going to refer you to, Interrogatory Response 6.2.3. And there, chronologically listed at the beginning --

A. Sorry, 6.2.3?

Q. Yes.

A. Yes, I have it.

Q. And the explanation in 6.2.3 is that a statement was based on independent initiatives being considered by MNR, and the international joint commission. And it is Hydro's understanding that MNR has been examining the possibility of increasing the water usage rates as a means of generating additional revenue, and that rates are currently being examined on an annual basis.

Now my question is: Is Hydro referring here to water charges for both thermal and hydraulic stations?

A. Again, Mr. Chapman, you will notice that this is an interrogatory from Panel 6 and our

presumption is that the answer is relative to hydraulic plant.

Q. All right. Do you know whether Hydro is currently paying any charges for water that is used for cooling?

A. Not to our knowledge.

Q. Are you aware that, for instance, in British Columbia, Manitoba, Nova Scotia, and Saskatchewan, that there are charges for water to cool thermal plants?

A. I am not aware of it.

Q. Ms. Ryan?

MS. RYAN: A. No, I wasn't aware of that.

Q. The response to 6.2.3 indicates that - at the very last line - that this could affect the operation of both fossil and nuclear stations. Now I take it that that could only mean water used for cooling purposes?

MR. SNELSON: A. That is what the answer suggests.

Q. But you are not the person to ask?

A. The question of water charges for thermal plant would go to the thermal panel or to the nuclear plan.

Q. I'm sorry, I missed that answer.

A. Sorry, the question about charges for water use for thermal may be better addressed to Panel 8 on thermal plant or Panel 9 on nuclear.

Q. And would that also apply to any discussions that Hydro may be having at the present time or recently have had with the authorities about what rates will be charged in the future with respect to the use of water?

A. Which authorities have you got in mind?

Q. The Ministry of Natural Resources and -- well, start with the Ministry of Natural Resources. Are you aware of any discussions going on at the present time about charges for the use of water?

A. No, I am not aware of anything other than the regular discussions that take place on water rentals. But Panel 6 would be aware of the latest discussions with the Ministry of Natural Resources.

Q. Just a general question. In these documents, there are four documents that are studies with respect to the use of water by utilities.

And the first one is by Bernard, Bridges and Scott, and it's entitled, "An evaluation of Potential Canadian Hydroelectric Rents." And the first

question is, are you aware of this study?

A. Sorry, which document is this, Mr. Chapman?

Q. It is found, the third document after the interrogatories, after the last interrogatory, the third document.

A. Well, I may have shuffled mine, so I am not sure which document you are referring to.

MS. PATTERSON: Under evaluation of potential?

MR. CHAPMAN: That's right. An evaluation of potential for potential Canadian hydroelectric rents.

MR. SNELSON: Yes, I have it now.

MR. CHAPMAN: Q. Are you familiar with that document? And by that, I mean --

THE CHAIRMAN: First of all, this is a document by Bernard; is that right? Is that what you said, the document you are referring to?

MR. CHAPMAN: Yes, sir.

THE CHAIRMAN: Perhaps you could just identify the document again, please, because I just didn't get a note of it.

MR. CHAPMAN: It is entitled "An Evaluation of Potential Canadian Hydroelectric Rents."

It is by a J.T. Bernard, and Bridges, G.E Bridges, and Anthony Scott, the University of British Columbia, the department of economics.

THE CHAIRMAN: I have got it now.

Has the panel got it?

MR. SNELSON: Yes, we have it.

THE CHAIRMAN: So, the question, are you aware of it?

MR. SNELSON: We became aware of it towards the end of the morning break this morning, along with a whole pile of documents.

MR. CHAPMAN: All right.

Q. And that would be true of the next document which is entitled the "Blue Gold Document."

MR. SNELSON: A. Yes.

Q. Which is called the Blue Gold Document: Hydro-electric Rent in Canada.

A. As I have said, we saw the pile of documents this morning. I haven't read any of these documents.

...

[4:10 a.m.] Q. And I just want to put the name of the documents on the record and then I am going to ask you, if you will, to bring them to the attention of Panel 6.

THE CHAIRMAN: I beg your pardon?

MR. CHAPMAN: To ask them if they would bring these documents to the attention of Panel 6, so that questions could be asked about them, when the hydraulic panel is before us.

THE CHAIRMAN: I don't see anything wrong in doing it, but it's a little tedious to go through them. If that's all you want to do about it, perhaps you could do that in a different fashion.

MR. CHAPMAN: I will, I will.

THE CHAIRMAN: We are not saying, I guess, or Hydro is not saying - I don't know whether it has been asked - whether Panel 6 is prepared to deal with them or not. So I don't know how you want to handle that, Mr. Chapman.

MR. CHAPMAN: Q. Well, I take it that you, Mr. Snelson, are not prepared to discuss these documents? As you have indicated, you just saw them for the first time today.

MR. SNELSON: A. That's correct.

THE CHAIRMAN: And if there are questions

you want to ask him about them, that's been done before. If you have got questions to ask them, you can ask them. If you have got statements in those documents that you want his comment on, you can do that. He just doesn't know anything about this particular document or the author, or I take it you don't know anything about the expertise of the author, or do you?

MR. SNELSON: In the cases that I have looked at, I am not familiar with the documents or the authors or their expertise.

THE CHAIRMAN: I am not quite sure what the purpose of putting these before this panel, or even Panel 6, is. That's what I want to get clear.

MR. CHAPMAN: All right. The documents, two of them are a gathering of statistics, Mr. Chairman, about the different charges in some provinces in Canada. And another two of the documents are generally a valuation of Hydro rents and the reasoning behind the charges for Hydro rents, and another document deals with trends toward charging higher prices for hydro, the use of water.

THE CHAIRMAN: I am sorry, charging higher...?

MR. CHAPMAN: Charging higher rents for

the use of water.

THE CHAIRMAN: Higher than what?

MR. CHAPMAN: Than they are now.

THE CHAIRMAN: Yes.

MR. CHAPMAN: But the answers that I am getting, it seems to me that it is up to me to bring these documents to the attention of the next panel and have them examine them.

Mr. Snelson has indicated that he doesn't seem to be that aware of Hydro's policy and the government's policy with respect to rental charges for the use of water.

THE CHAIRMAN: Perhaps you could just help us a little bit to say what, in general, is the point you are trying to make with this particular analysis.

MR. CHAPMAN: The point is, sir, that it is my client's position that more should be charged for the use of water than presently is being charged.

THE CHAIRMAN: Well, that, I suppose, would be usually addressed to people who are imposing the charges, would it not?

MR. CHAPMAN: Well, as is often the case, a corporation like Hydro often has a lot to say about what is charged.

THE CHAIRMAN: But you can't expect Hydro to be advocating higher charges for water rates, or are you? Are you suggesting they should be doing that?

MR. CHAPMAN: I would prefer to put it this way: It's a suggestion that Hydro should realize what the real cost to the environment is of the use of the water and that it should be taken into consideration by this panel when we are looking at the hydraulic situation.

I agree, that I don't expect Hydro to want to be charged more for the water rates, but nevertheless, I would think that it is relevant to this hearing to know if they are being charged the proper amount from an environmental point of view. But as I have indicated, I don't think that this panel is the proper panel to address those questions to.

If Hydro had to pay the proper cost, it's my submission that electricity would be more expensive.

THE CHAIRMAN: Well, no doubt, that's true. But I am not quite sure how this panel, or any other panel from Hydro, can help you much about that. However, perhaps if you could give Mrs. Formusa the list of documents and then she can refer them to Panel 6.

MR. CHAPMAN: I will do that.

Q. I suppose, Mr. Snelson, you would agree that if there is a trend toward charging higher water rates, that that would have an effect on your plan, wouldn't it?

MR. SNELSON: A. Yes. Water rentals is one factor that is taken into account in evaluating the potential for new hydroelectric development.

Q. And of course there is a new hydroelectric development proposed in this plan.

A. Yes.

Q. And so it could have an effect on the plan, you agreed with that, the fact that the rents go up.

A. If the rents were higher, then it would tend to reduce the economic attractiveness of new hydroelectric development, yes.

Q. But I believe you also indicated that you are not keeping track of what other jurisdictions are paying for water.

A. Personally, I am not. Other people who are more involved in water rentals may well be.

Q. All right. Dealing with a hydraulic station generally, there are some stations that I call run-of-the-river stations and there are others that have reservoirs; is that correct?

A. Yes, you can make that classification.

Q. And isn't it fair to say that a hydraulic station with a reservoir obviously must entail flooding?

A. At the time it is constructed, there will usually be some flooding, yes.

Q. In general, are you able to say, is more flooding required for a station constructed and operated for peaking, as opposed to intermediate or base generation? Of course, I am speaking about just a hydraulic station.

A. I don't think that you can distinguish the amount of flooding by whether it's peaking or base. Whether it's peaking or base is more a factor of how it's operated, than the amount of land that is flooded.

Q. All right. If it's operated -- you misunderstood me. I probably didn't put the question properly.

A. No. I...

Q. If it's operated for peaking--

A. Yes.

Q. --what do you have to say about whether or not the effect on the environment is, if a

hydraulic station is operating for peaking as opposed to intermediate or base generation?

A. If it's operated for peaking, then there will be fluctuations in river flows downstream of the plant that would not be there if it was operated base load. And there will be, perhaps, depending on the cycle, some fluctuations in the reservoir above the dam that will be more than for a base load station.

Q. And would you explain to the panel why that is the case?

A. On a peaking operation, and let's, for the sake of example, assume that it is a daily peaking operation and that the plant runs during the daytime peak hours and is shut down overnight, then during the daytime, the flow will be high below the station as the water is used, and the level of the water above the dam will be tending to fall.

During the nighttime, when the plant isn't operating, the flow below the dam will be less, and in the extreme, zero, and the level behind the dam will be tending to rise back to its early morning level to start the peaking operation for the next day.

And this is the sort of fluctuations which Mr. Barrie described in his direct evidence that has to be controlled and does sometimes lead to

operating constraints, to reduce environmental effects to acceptable levels.

Q. And one of those environmental effects, I take it, would be, for instance, erosion of the river banks?

A. Downstream fluctuations in flow may contribute to erosion. I don't know whether Mr. Barrie wants to add anything to that.

MR. BARRIE: A. Yes, that's true.

MR. SNELSON: A. There are mitigating measures that can be taken.

Q. Now, insofar as environmental changes relating to reservoir creation, the DSP environmental analysis says at page 4-5, "The related problems of land/habitat displacement, loss of riverine fish habitat, increased mercury levels in the reservoir, and erosion/siltation problems," and you agree with that, I take it.

A. Sorry, where was the reference?

Q. That, I believe, is Hydro's Exhibit No. 4.

A. Yes. I am just trying to get the page.

Q. Unfortunately, my page reference is page 4-5 of the environmental analysis.

THE CHAIRMAN: Whereabouts are you reading in that page?

MR. SNELSON: Are you in the top of the centre column?

MR. CHAPMAN: Q. The major environmental change.

MR. SNELSON: A. Yes, I have it.

THE CHAIRMAN: It starts out, "Hydraulic developments, however, are not without environmental effects"?

MR. CHAPMAN: Yes.

THE CHAIRMAN: What is the question?

MR. CHAPMAN: Q. You agree with that statement, of course.

MR. SNELSON: A. Yes.

Q. And mercury levels in the reservoir can be a problem, you agree with that?

A. There is some evidence that mercury can be released due to flooding. This issue, I believe, is probably - and this whole environmental discussion of future hydraulic plant - is better addressed to Panel 6.

Q. All right. On May 21st, Mrs. Formusa, and I am referring to May 21st transcript, page 2762, Mrs. Formusa asked Ms. Ryan to explain the

concern with respect to mercury in reservoirs. And at line 14:

"In some hydroelectric developments outside Ontario, reservoir flooding has resulted in inceased concentrations of methyl mercury in fish, both in the reservoir and downstream of the reservoir. This is a concern to local residents who may consume large quantities of the fish.

"QUESTION: What is Ontario Hydro doing about this?

"ANSWER: In Ontario Hydro's existing reservoirs, the concentrations of mercury in fish appear to be within the range normally found in natural water bodies."

And it goes on to say how you recognize the concern and you are participating in studies for the future.

Now, you are familiar, I take it, with the Ogoki Reservoir, O-G-O-K-I?

Ms. RYAN: A. Nominally.

Q. And I understand it was built approximately in 1943.

A. I don't know.

Q. And I like to refer now to the Little Jackfish Environmental Assessment at page 7-29.

THE CHAIRMAN: What document is that, please?

MR. CHAPMAN: That's a document that's in our list. There are two Little Jackfish River documents, Mr. Chairman. The first is the assessment, Little Jackfish River Hydroelectric Project Environmental Assessment, and the second is the Little Jackfish River Hydroelectric Project Environmental Assessment Summary.

THE CHAIRMAN: Is there is a page number or a tab number that I can look to, to find it?

MR. CHAPMAN: My understanding is that there are tabs for the documents in your material, Mr. Chairman. It will be Jackfish EA.

THE CHAIRMAN: Which is it, the summary or the assement you want us to see?

MR. CHAPMAN: The assessment.

THE CHAIRMAN: I have got a document that says Little Jackfish River Hydroelectric Project Environmental Assessment, it starts at page 7-22; is that right?

MR. CHAPMAN: That's correct.

THE CHAIRMAN: It goes on for a few

pages. Just bear with me for a moment, please.

MR. CHAPMAN: Yes.

THE CHAIRMAN: What is this document? I am not quite sure I know what it is. Is it the Decision of the Environmental Assessment Board? What is it?

MR. CHAPMAN: It's one of Hydro's document.

THE CHAIRMAN: It's a Hydro document?

MR. CHAPMAN: Yes.

THE CHAIRMAN: All right, okay.

How do you propose to make these exhibits from this binder here, how do you intend to do that?

You have it here? What are you doing, then, are you marking it?

THE REGISTRAR: Not yet, no.

MS. MORRISON: Not unless you say.

THE CHAIRMAN: Well, I guess we should mark this as an exhibit, if you are going to ask questions about it.

MR. CHAPMAN: Thank you.

THE CHAIRMAN: Could we do the whole binder as an exhibit?

MR. CHAPMAN: That will be fine, as far as I am concerned, if it's fine with the panel.

THE CHAIRMAN: Will that be all right with you, Mrs. Formusa? These are little extracts; they are not the whole thing.

MRS. FORMUSA: I understand that.

But I am just wondering the utility of doing that for documents which I suspect my witnesses will say they won't be able to get into and that they would be more for Panel 6. I am almost positive Ms. Ryan can't deal with the Little Jackfish EA, but I know that Panel 6 can.

Most of those matters, the specifics of which Mr. Chapman is beginning to refer to, were in the scoping package deferred to Panel 6. You recall that we had a statement of proposed issues and then where intervenors raised specifics about mercury, the Ogoki diversion, things like that, we specified that they would go to Panel 6.

All I am suggesting is that it may not be useful if we are going to enter it as an exhibit now, and the witnesses are going to say, we can't deal with it.

THE CHAIRMAN: My problem is, I don't think it's a good idea to put the whole book in, because no one is going to be able to find the references they are looking for. So I think if this is

going in as an exhibit, this partial extract from the Little Jackfish River Hydroelectric Project Environmental Assessment, then it should have a number attached to it, so that when people are trying to find when it was referred to in the hearing, they can reference it with a number.

...

[4:30 p.m.] I don't know what questions he is going to ask about it. You don't know. And they don't know whether they can answer it or not.

MR. CHAPMAN: So we will give it a number, Mr. Chairman?

MRS. FORMUSA: All I can tell you is that none of the witnesses on the panel have expertise in natural environmental matters. Since this section --

THE CHAIRMAN: That includes Ms. Ryan, does it?

MS. RYAN: Do you want me to speak for myself?

MRS. FORMUSA: Yes, please.

MS. RYAN: On the matters dealing with mercury in reservoirs, from a general point of view, I said what I was going to in direct evidence. But most of the work that is being done is for future hydraulic generation, and that's where all of our emphasis is being put. And the Little Jackfish Environmental Assessment is for a future project, so, you would get far more complete answers from Panel 6 on this matter.

MR. CHAPMAN: Q. Well, I haven't asked the question yet, but the question is fairly basic and I don't think there will be any problem; and if there is, I will stop.

THE CHAIRMAN: Why don't we compromise? Ask the question. If it turns out that we get some kind of an answer, then we will put some kind of a number on it. All right.

MR. CHAPMAN: Fine.

Q. Now I am referring, Mrs. Ryan, to page 7-29. And near the top of the right-hand column, in fact, right at the top, the sentence starting:

> "Mean mercury concentrations were higher in walleye from Ogoki Reservoir and Mojikit Lake than in walleye from the Little Jackfish River."

And it gives the measurements.

Then reading down further:

> "Mean mercury concentration in walleye from White Clay Lake, a reference station on the Ogoki River upstream of the Ogoki Reservoir, exceeded the...guideline for safe consumption, but was still significantly lower than the mean concentration in walleye from the Ogoki Reservoir."

Now to me - and you correct me if I am wrong - that suggests that there is a problem with respect to mercury in the reservoir because of the

reservoir. And I use that as an example of one of Hydro's hydraulic stations.

MS. RYAN: A. I am afraid I don't know enough detail about the method of measurement and the water configuration itself to answer you with a complete answer.

THE CHAIRMAN: I am going to suggest that we now adjourn for the day and that you and Mrs. Formusa get together and work out your cross-examination so we don't have to run into this problem constantly, of this particular witness panel not being able to answer it and it being in some other witness panel.

MR. CHAPMAN: I would be more than glad to.

THE CHAIRMAN: We will adjourn until tomorrow morning at ten o'clock.

But if you do that, I would appreciate it.

THE REGISTRAR: This hearing will adjourn until ten o'clock tomorrow morning.

---Whereupon the hearing was adjourned at 4:35 p.m., to be reconvened on Wednesday, May 29, 1991, at 10:00 a.m.

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E R R A T A
and
C H A N G E S

To transcript for Tuesday, the 21st day of May, 1991, Volume 16.

Page No.	Line No.	Discrepancy
2733	17	work s/r look
2823	15	for s/r than
2831	2	long s/r wrong
2832	10	themselves s/r them
	15	Maine s/r MAIN
2844	11	for s/r to
2846	14	moving from s/r adding
2847	18	is none s/r has none
2853	9	in s/r and
2864	12	delete "an"

To transcript for Wednesday, the 22st day of May, 1991, Volume 17.

Page No.	Line No.	Discrepancy
2917	9	were s/r we are
2921	25	transmission s/r transmission and
2931	21	complete s/r completed
2963	9	2 s/r to
2979	3	lessor s/r lesser
3029	3	know s/r no

E R R A T A
and
C H A N G E S
(Continued)

To transcript for Thursday, the 23rd day of May, 1991, Volume 18.

Page No.	Line No.	Discrepancy
3066	22	2 per cent s/r 1 to 2 per cent
3145	8	shorter list s/r longer list
3151	4	sepra s/r Sepr
	8	"
	18	"
3154	14	PS&E s/r PSOD
3214	3	surface reserve s/r surplus reserve
3219	14	some placement s/r displacement

CHANGES BY MRS. FORMUSA
Volumes 16 & 17

2857	8	programs s/r stations
2858	11	replacement s/r refurbishment
2860	1	hydraulic s/r fossil
	3	fossil s/r hydraulic
2950	2	add s/r multiply by
2957	22	by customer damage cost should be added following F&D run
2978	19	18 months s/r 12 months
3017	8	very quickly s/r in about eight hours